ALABAMA POWER CO
Form 10-K
February 28, 2013
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

þ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the Fiscal Year Ended December 31, 2012

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

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		Alabama Power Company
5.20% Series	5.83% Series	
5.30% Series		
Class A Preferred Stock, non-cumulative, Par value $25 per share 6 1/8% Series		Georgia Power Company
Senior Notes 8.20% Series 2008C		
Senior Notes 5.25% Series H 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, 2012.

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. x

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.)

Aggregate market value of The Southern Company's common stock held by non-affiliates of The Southern Company at June 30, 2012: $40.5 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, 2013
The Southern Company	Par Value $5 Per Share	868,969,827
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	4,542,717
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 2013 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 2013 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.

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DEFINITIONS

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

Term	Meaning
2010 ARP	Alternative Rate Plan approved by the Georgia PSC for Georgia Power for the years 2011 through 2013
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	Dalton Utilities
DOE	United States Department of Energy
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	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 are subject to joint commitment and dispatch in order to serve their combined load obligations
PowerSouth	PowerSouth Energy Cooperative
PPA	Power Purchase Agreement

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DEFINITIONS
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Term	Meaning
Progress Energy Florida	Florida Power Corporation, d/b/a Progress Energy Florida, Inc.
PSC	Public Service Commission
registrants	Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power
RUS	Rural Utilities Service (formerly Rural Electrification Administration)
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
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, dividend payout ratios, projections for the qualified pension plan, postretirement benefit plan, and nuclear decommissioning trust fund contributions, financing activities, start and completion dates of construction projects, plans and estimated costs for new generation resources, filings with state and federal regulatory authorities, impact of the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010, 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 byproducts, and emissions of sulfur, nitrogen, carbon, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, financial reform legislation, 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, 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, including the development and construction of facilities with designs that have not been finalized or previously constructed, 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 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;
- regulatory approvals and actions related to Plant Vogtle Units 3 and 4, including Georgia PSC approvals, NRC actions, and potential DOE loan guarantees;
- regulatory approvals and legislative actions related to the Kemper IGCC, including Mississippi PSC approvals and legislation relating to cost recovery for the Kemper IGCC, the SMEPA purchase decision, satisfaction of requirements to utilize investment tax credits and grants, and the outcome of any proceedings regarding the Mississippi PSC's issuance of the CPCN for the Kemper IGCC;
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the inherent risks involved in operating and constructing nuclear generating facilities, including environmental, health, regulatory, natural disaster, terrorism, and financial risks;

- the performance of projects undertaken by the non-utility businesses and the success of efforts to invest in and develop new opportunities;
- internal restructuring or other restructuring options that may be pursued;

- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to Southern Company or its subsidiaries;
- the 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 availability or benefits of proposed 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, which is also an operating public utility company. Southern Power and it subsidiaries construct, acquire, own, and manage generation assets, including renewable energy projects, and sell electricity at market-based rates in the wholesale market. Southern Power 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's subsidiaries are also admitted to do business in the States of 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 Carolina Power & Light Company (d/b/a Progress Energy Carolinas, Inc.), Duke Energy Corporation, 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. 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 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 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, 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 and power pool transactions. Southern Power 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, 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 is an electric wholesale generation subsidiary with market-based rate authority from the FERC. Southern Power and its subsidiaries construct, acquire, own, and manage generation assets, including renewable energy projects, and sell electricity at market-based rates in the wholesale market. Southern Power'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, 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 Southern Power, 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. The solar facility began commercial operation on July 21, 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. The solar facility began commercial operation on October 28, 2012. Granville has a PPA covering the entire output of the plant from 2012 through 2032. Spectrum is constructing a 30-MW solar photovoltaic facility in North Las Vegas, Nevada. The solar facility is expected to begin commercial operation in mid-2013. Spectrum has a PPA covering the entire output of the plant from 2013 through 2038. These acquisitions added a total of 47 MWs of solar capacity to Southern Power's generation portfolio and are in accordance with Southern Power's overall growth strategy.

As of December 31, 2012, Southern Power had 8,764 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 2013 through 2015, 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 existing environmental statutes and regulations. In 2013, 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	$1,052	$—	$555	$—	$497
Environmental **	957	195	476	158	129
Transmission & Distribution Growth	655	176	284	16	30
Maintenance (Generation, Transmission, and Distribution)	1,339	597	611	145	135
Nuclear Fuel	269	97	172	—	—
General Plant	190	84	84	16	5
	4,462	1,149	2,182	335	796
Southern Power	910	—	—	—	—
Other subsidiaries	108	—	—	—	—
Total	$5,480	$1,149	$2,182	$335	$796

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

** Reflects cost estimates for existing environmental regulations, including the MATS rule. The Southern Company system continues to monitor the development of the EPA's proposed water and coal combustion byproducts 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. See also MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" of Southern Power 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.

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. 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.

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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 2010 through 2012.

The traditional operating companies have agreements in place from which they expect to receive substantially all of their coal burn requirements in 2013. These agreements have terms ranging between one and eight years. In 2012, the weighted average sulfur content of all coal burned by the traditional operating companies was 0.76 % 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 2012, 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 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, has agreements in place for the natural gas burn requirements of the Southern Company system. For 2013, SCS has contracted for 439 billion cubic feet of natural gas supply under agreements with remaining terms up to eight 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 15 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.

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. 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.

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, including the furnishing of protective capacity by Mississippi Power 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. On February 28, 2012, the Mississippi PSC approved the sale and transfer of 17.5% of the Kemper IGCC to SMEPA. On June 29, 2012, Mississippi Power and SMEPA signed an amendment to the asset purchase agreement whereby SMEPA extended its option to purchase until December 31, 2012 and 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 September 27, 2012, SMEPA received a conditional loan

commitment from the RUS to provide funding for SMEPA's purchase of an undivided interest in the Kemper IGCC. On December 31, 2012, Mississippi Power and SMEPA agreed to extend SMEPA's option to purchase through December 31, 2013. 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. In addition, Georgia Power previously served the full requirements of the City of Hampton's electric distribution system under a market-based contract that terminated on December 31, 2012. 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 as the result of self-generation (as described below) by customers and 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 nine industrial customers. Under the terms of these contracts, Alabama Power purchases excess energy generated by such companies. During 2012, Alabama Power purchased approximately 222 million KWHs from such companies at a cost of $8.6 million.

Georgia Power currently has contracts in effect with 10 small power producers whereby Georgia Power purchases their excess generation. During 2012, Georgia Power purchased 18 million KWHs from such companies at a cost of $0.6 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 2012, Georgia Power purchased 380 million KWHs at a cost of $27 million from this facility.

Also during 2012, Georgia Power purchased energy from seven customer-owned generating facilities. Six of the seven customers provide only energy to Georgia Power. These six customers make no capacity commitment and are not dispatched by Georgia Power. Georgia Power has a contract with the remaining customer for eight MWs of dispatchable capacity and energy. During 2012, Georgia Power purchased a total of 37 million KWHs from the seven 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 2012, Gulf Power purchased 219 million KWHs from such companies for approximately $6.3 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 2012, 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 and 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. On November 15, 2012 , the FERC denied the Smith Lake Improvement and Stakeholders' Association's request for rehearing. On December 17, 2012, the Smith Lake Improvement and Stakeholders' Association filed for rehearing of the November 15, 2012 order and, on January 16, 2013, the FERC denied the request.

In 2006, Alabama Power initiated the process of developing an application to relicense the Martin Dam Project located on the Tallapoosa River. In June 2011, Alabama Power filed an application with the FERC to relicense the Martin Dam Project. The current Martin license will expire on June 8, 2013.

In 2010, Alabama Power initiated the process of developing an application to relicense the Holt hydroelectric project located on the Warrior River. The current Holt license will expire on August 31, 2015, and the application for a new license is expected to be filed with the FERC no later than August 31, 2013.

In 2007, Georgia Power began the relicensing process for Bartlett's Ferry which is located on the Chattahoochee River near Columbus, Georgia. On December 14, 2012, Georgia Power filed an application with the FERC to relicense the Bartlett's Ferry project. 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.

In 2002, the NRC extended the licenses of Georgia Power's Plant Hatch Units 1 and 2 until 2034 and 2038, respectively. In 2005, the NRC extended the licenses of Alabama Power's Plant Farley Units 1 and 2 until 2037 and 2041, respectively. In 2009, the NRC extended the licenses of Plant Vogtle Units 1 and 2 to 2047 and 2049, respectively.

On February 10, 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 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 byproducts, 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 byproducts. 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 and each of the traditional operating companies 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. The impact of SEGCO's ultimate compliance strategy on such PPA costs cannot be determined at this time; however, if such 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 byproducts, 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. 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 demand-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 the new nuclear units 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" of Mississippi Power in Item 7 herein for information on cost recovery plans and a settlement agreement between Mississippi Power and the Mississippi PSC.

The traditional operating companies and Southern Power and 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 2012 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 MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Integrated Resource Plans" 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. 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.

Gulf Power's most recent 10-year site plan was classified by the Florida PSC as "suitable" on November 28, 2012. 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 Byproducts," and "Environmental Matters – Global Climate Issues" of Gulf Power in Item 7 herein. Gulf Power continues to consider and evaluate various potential planning scenarios for units at each of Gulf Power’s coal-fired generating plants. This work indicates that, depending on the final requirements in these anticipated EPA regulations and any legislation or regulations relating to greenhouse gas emissions, as well as estimates of long-term fuel prices, Gulf Power may conclude that it is more economical to retire certain of its coal-fired generating units prior to 2021 and to replace such units with new or purchased capacity.

In 2009, the Florida PSC adopted new numerical conservation goals for Gulf Power along with other electric utilities in the state. The Florida PSC adopted more aggressive goals due in part to the consideration of possible greenhouse gas emissions costs incurred in connection with possible climate change legislation and a change in the manner in which the Florida PSC considers the effect of so-called "free-riders" on the level of conservation reasonably achievable through utility programs. Gulf Power's plans and programs to meet the new goals were submitted to the Florida PSC for review in 2010 and were approved in January 2011. 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 and Mississippi Power under "Integrated Coal Gasification Combined Cycle – 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 26,439 employees on its payroll at December 31, 2012.

	Employees at December 31, 2012
Alabama Power	6,778
Georgia Power	8,094
Gulf Power	1,416
Mississippi Power	1,281
SCS	4,516
Southern Nuclear	4,077
Southern Power*	0
Other	277
Total	26,439

* 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 an agreement with the IBEW covering wages and working conditions, which is in effect through August 15, 2014.
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.
Mississippi Power has an agreement with the IBEW covering wages and working conditions, which is in effect through August 15, 2014. On February 11, 2013, Mississippi Power signed an agreement with the IBEW related 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.
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 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 byproducts, 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 increase in the future. Through 2012, the traditional operating companies had invested approximately $8.7 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 is expected to propose 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 byproducts (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 byproducts, 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 has determined that emissions of carbon dioxide and other greenhouse gases are regulated pollutants under the Prevention of Significant Deterioration preconstruction permit program and the Title V operating permit program, which both apply to power plants and other commercial and industrial facilities. On April 13, 2012, the EPA published proposed regulations to establish standards of performance for greenhouse gas emissions from new fossil fuel steam electric generating units and has indicated that it will propose standards of performance for existing units in the future.

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; 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. Southern Company, the traditional operating companies, and Southern Power are also parties to suits alleging that emissions of carbon dioxide, a greenhouse gas, contribute to global climate change. 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 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. 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 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 byproducts, 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. Proposed or potential changes in federal law, regulatory uncertainty, and industry restructuring are expected to continue to present challenges to the regulatory and/or operational structure of transmission and competition on the wholesale level. Any changes could have an adverse impact on the ownership of transmission assets and/or future revenues. As an example, pending FERC regulation pertaining to cost allocation for regional transmission projects could require Southern Company and its utility subsidiaries to subsidize costs outside of the Southern Company system's retail service territory.

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 and penalties as a result of mandatory reliability standards.

Owners and operators of bulk power systems, including the traditional operating companies, are subject to mandatory reliability standards enacted by the North American 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 may result in 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 8.0%, of Southern Company's generation capacity as of December 31, 2012. 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 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 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 others 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; and

- the impact of a natural disaster.

Alabama Power and Georgia Power maintain decommissioning trusts and external insurance coverage to minimize the 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. 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 NRC also issued three orders and the NRC staff issued guidance on acceptable approaches for compliance with these orders before the December 31, 2016 deadline, that included, among other items, additional mitigation strategies for beyond-design-basis events, enhanced spent fuel pool instrumentation capabilities, hardened vents for certain classes of containment structures, including the one in use at Plant Hatch, site specific evaluations for seismic and flooding hazards, and various plant evaluations to ensure adequate coping capabilities during station blackout and other conditions. 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.

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. 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 or prohibit the operation or licensing of any domestic nuclear unit. 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 business networks. Despite the implementation of robust security measures, all technology systems 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 technology systems were to fail 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 are 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. 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. It is possible that advances in technology will reduce the cost of alternative methods of producing power to a level that is competitive with that of most central station power electric production. If these technologies became cost competitive and achieved economies of 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.

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 or increased costs. Such operating challenges include lack of resources, loss of knowledge, and a lengthy time period associated with skill development, especially with the workforce needs associated with new nuclear and IGCC construction. 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.

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 involve facility 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;
- 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;
- 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;
- 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 new nuclear units 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. 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.

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 also may 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 construction of the Kemper IGCC. 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 on February 10, 2012. Receipt of the COLs allowed full construction to begin. Separate groups of petitioners have filed petitions in the U.S. Court of Appeals for the District of Columbia Circuit seeking judicial review of the NRC's issuance of the COLs and certification of the DCD. Additional technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4, at the federal and state level, 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. Georgia Power's eighth VCM report requests approval for an additional $0.2 billion of construction capital costs incurred through December 31, 2012. 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, the eighth VCM also requests an amendment to the certificate to increase the estimated in-service capital cost of Plant Vogtle Units 3 and 4 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. Associated financing costs during the construction period are estimated to total approximately $2.0 billion.

Georgia Power, OPC, MEAG Power, and the City of 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. 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 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.

In addition, there are processes in place that are designed to assure compliance with the requirements specified in the DCD and COLs, including rigorous inspections by Southern Nuclear and the NRC that occur throughout construction. License amendment requests are pending with the NRC to address a few non-safety significant deviations that were identified in the fourth quarter of 2012 with respect to the rebar design for the Plant Vogtle Unit 3 nuclear island. Various design and other issues are expected to arise as construction proceeds, which may result in additional license amendments or require other resolution. If any license amendment requests 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, additional delays in the fabrication and assembly of structural modules or the failure of such modules to meet applicable standards, or other issues may further impact project schedule and costs. 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.

In addition, Mississippi Power is constructing the Kemper IGCC. Mississippi Power and SMEPA are parties to an amended Asset Purchase Agreement whereby SMEPA agreed to purchase a 15% undivided interest in the Kemper

IGCC. 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.

The Mississippi PSC originally approved Mississippi Power's request for a CPCN for the construction of the Kemper IGCC in 2010. Following judicial proceedings relating to its original order, the Mississippi PSC issued a detailed order (2012 MPSC Order) confirming the CPCN for the Kemper IGCC. On April 26, 2012, the Sierra Club appealed the 2012 MPSC Order to the Chancery Court of Harrison County, Mississippi (Chancery Court). On December 17, 2012, the Chancery Court affirmed the 2012 MPSC Order which confirmed the issuance of the CPCN for the Kemper IGCC. On January 8, 2013, the Sierra Club filed an appeal of the Chancery Court's ruling with the Mississippi Supreme Court. Additional judicial challenges that may impact the Kemper IGCC are pending, including a challenge of the constitutionality of the Baseload Act that is pending before the Mississippi Supreme Court.
The certificated cost estimate of the Kemper IGCC included in the 2012 MPSC Order was $2.4 billion, net of $245.3 million of grants awarded to the project by the DOE under the Clean Coal Power Initiative Round 2 (CCPI2) and excluding the cost of the

lignite mine and equipment, the cost of the CO_2 pipeline facilities, and financing costs related to the Kemper IGCC. The 2012 MPSC 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. Exemptions from the cost cap included in the 2012 Mississippi PSC Order included the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, financing costs, 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).
Mississippi Power's current cost estimate for the Kemper IGCC (net of the $245.3 million CCPI2 grant, and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, financing costs, and certain general exceptions as contemplated in the 2012 Mississippi PSC Order and the settlement agreement between Mississippi Power and the Mississippi PSC entered into on January 24, 2013 (Settlement Agreement) that must be specifically approved by the Mississippi PSC) is approximately $2.88 billion. While Mississippi Power continues to believe its cost estimate and schedule projection remain appropriate based on the current status of the project, it is possible that Mississippi Power could experience further cost increases and/or schedule delays with respect to the Kemper IGCC. Certain factors have caused and may continue to cause the costs for the Kemper IGCC to increase and/or schedule delays to occur including, but not limited to, costs and productivity of labor, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay or non-performance under construction or other agreements, and unforeseen engineering problems. To the extent it becomes probable that costs beyond any permitted exceptions to the cost cap will exceed $2.88 billion or it becomes probable that the Mississippi PSC will disallow a portion of the costs relating to the Kemper IGCC, including certain general exceptions as contemplated in the 2012 Mississippi PSC order and the Settlement Agreement, charges to expense may occur and these charges could be material.
The 2012 MPSC 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 in-service date of the Kemper IGCC. On June 22, 2012, the Mississippi PSC denied Mississippi Power's proposed Certificated New Plant-A (CNP-A) rate schedule and the 2012 rate recovery filings submitted by Mississippi Power which provided for recovery of financing costs during 2012, 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. On July 9, 2012, Mississippi Power appealed the Mississippi PSC's June 22, 2012 decision to the Mississippi Supreme Court and requested interim rates under bond of $55.3 million.
On January 24, 2013, Mississippi Power and the Mississippi PSC entered into a Settlement Agreement that (1) establishes the process for resolving matters regarding cost recovery related to the Kemper IGCC for the purpose of mitigating risks to Mississippi Power and its customers and expediting the regulatory process associated with future rate filings required under the Settlement Agreement and (2) resolves Mississippi Power's CNP-A rate appeal before the Mississippi Supreme Court.
On February 12, 2013, the Mississippi Supreme Court granted Mississippi Power and the Mississippi PSC's joint filing for dismissal of Mississippi Power's appeal of the Mississippi PSC's June 22, 2012 decision.
Under the terms of the Settlement Agreement, Mississippi Power and the Mississippi PSC will follow certain agreed-upon regulatory procedures and schedules for resolving the cost recovery matters related to the Kemper IGCC. These procedures and schedules include the following: (1) Mississippi Power's filing within 30 days of the Settlement Agreement of a new request to increase rates in 2013 in an amount not to exceed a $172 million annual revenue requirement, based upon projected investment as of December 31, 2013, to be recorded to a regulatory liability to be used to mitigate rate impacts when the Kemper IGCC is placed in service (which filing for $172 million was made on January 25, 2013); (2) the Mississippi PSC's decision on that matter within 50 days of Mississippi Power's request; (3) Mississippi Power's collaboration with the Mississippi Public Utilities Staff to file with the Mississippi PSC within three months of the Settlement Agreement 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 (which filing was made

on February 26, 2013 as described below); (4) the Mississippi PSC's decision on the rate recovery plan within four months of the filing; (5) Mississippi Power's agreement to limit the portion of prudently-incurred Kemper IGCC costs to be included in rate base to the \$2.4 billion certificated cost estimate, plus costs related to the lignite mine and CO_2 pipeline as well as any other costs permitted or determined to be excluded from the cost cap, provided that this limitation will not prevent Mississippi Power from securing alternate financing to recover any prudently-incurred Kemper IGCC costs, including financing costs and plant costs above the \$2.4 billion certificated cost estimate, not otherwise recovered in any Mississippi PSC rate proceeding contemplated by the Settlement Agreement; and (6) the Mississippi PSC's completion of its prudence review of the Kemper IGCC costs incurred through 2012 within six months of the Settlement Agreement, an additional prudence review upon considering the seven-year rate plan for costs incurred through the most recent reporting period, and a final prudence review of the remaining project costs within six months of the Kemper IGCC's in-service date.

Legislation to authorize a multi-year rate plan and legislation to provide for alternate financing through securitization was passed in the Mississippi legislature and was signed by the Governor on February 26, 2013. Mississippi Power contemplates using securitization as provided in the legislation as its form of alternate financing for prudently-incurred Kemper IGCC costs, including financing costs and plant costs above the $2.4 billion certificated cost estimate, not otherwise recovered in any Mississippi PSC rate proceeding contemplated by the Settlement Agreement.

On February 26, 2013, Mississippi Power in compliance with the Settlement Agreement, filed with the Mississippi PSC a rate recovery plan for the Kemper IGCC for 2014 through 2020, the first seven years of operation of the Kemper IGCC. The rate recovery plan proposes recovery of an annual revenue requirement of approximately $150 million of Kemper IGCC-related operational costs and rate base amounts, including plant costs equal to the $2.4 billion certificated cost estimate. Approval of Mississippi Power's request to increase rates in 2013 to mitigate the rate impacts of the Kemper IGCC filed on January 25, 2013 is integral to the rate recovery plan as the proposed filing contemplates amortization of the regulatory liability to be used to mitigate rate impacts from 2014 through 2020, based on a fixed amortization schedule that requires approval by the Mississippi PSC. Under the rate recovery plan filing, Mississippi Power proposes annual recovery to remain the same from 2014 through 2020 and, while it is the intent of Mississippi Power for the actual revenue requirement to equal the proposed revenue requirement for certain items, Mississippi Power proposes that the annual differences for those items through 2020 will be deferred, subject to accrual of carrying costs, and the cumulative balance will be reviewed at the end of the term of the Settlement Agreement by the Mississippi PSC for determination of the manner of the recovery. Mississippi Power proposes to secure recovery of prudently-incurred Kemper IGCC costs, including financing costs and plant costs above the $2.4 billion certificated cost estimate, not otherwise recovered in any Mississippi PSC rate proceeding contemplated by the Settlement Agreement to be provided for with alternate financing through securitization. The rate recovery necessary to recover the annual costs of securitization is proposed to be filed and begin after the Kemper IGCC is placed in service.

Under the terms of the Settlement Agreement, Mississippi Power has the right to terminate the Settlement Agreement if certain conditions, including the passage of multi-year rate plan legislation that is contemplated under the Settlement Agreement, 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.

The ultimate outcome of these matters, including the determinations of prudency and the specific manner of recovery of prudently-incurred costs, is subject to further legislative and 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 or 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. In addition, the proportion of natural gas generation to the total fuel mix is likely to increase in the future. 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 as well as the financial stability of the customers of the traditional operating companies and Southern Power.

Southern Company, the traditional operating companies, and Southern Power are exposed to risks related to general economic conditions in their applicable service territory and are thus impacted by the economic cycles of the customers each serves. Any economic downturn or disruption of financial markets, both nationally and internationally, could negatively affect the financial stability of the customers and counterparties of the traditional operating companies and Southern Power. As territories served by the traditional operating companies and Southern Power experience economic downturns, energy consumption patterns may change and revenues may be negatively impacted. Customer growth and customer usage can be affected by economic factors in the service territory of the traditional operating companies and Southern Power and elsewhere, including, for example, job and income growth, housing starts, new home prices, and the economic impact on customers of federal fiscal decisions. Adverse economic conditions, a population decline, and/or business closings in the territory served by the traditional operating companies or Southern Power or slower than anticipated customer growth as a result of a recessionary economy or otherwise could also have a negative impact on revenues and could result in greater expense for uncollectible customer balances. As with other parts of the country, the territories served by the traditional operating companies and Southern Power have been impacted by the recent economic recession. The traditional operating companies have experienced residential and commercial sales that continue to be below historical trends due to the recent economic recession. Southern Power is expected to continue to experience reduced future revenues for its requirements customers due to the recent economic recession. The timing and extent of the recovery cannot be predicted.

Stronger or more rapid than expected economic growth, coupled with the effects of current and future environmental regulations applicable to the traditional operating companies or Southern Power, could impact the ability of the traditional operating companies and/or Southern Power to meet the energy demands of their customers. Weaker or slower than expected economic growth could have a negative impact on revenues, could result in greater expense for uncollected customer balances, and could adversely impact the value of generation assets of the traditional operating companies and/or Southern Power.

All of the factors discussed above could adversely affect Southern Company's, the traditional operating companies', and/or Southern Power's level of future net income.

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, and droughts 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 could negatively affect their ability to access capital at reasonable costs and/or could require Southern Company, the traditional operating companies, or Southern Power 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, 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 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 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, 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 may not be able to extend its 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 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 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 any 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. 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. 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 receive certain benefits related to such programs.

Additionally, Southern Company, the traditional operating companies, and Southern Power could also be negatively impacted if any future energy price increases result in a decrease in customer usage.

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.

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, as has been experienced in prior periods, 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.

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Item 2. PROPERTIES

Electric Properties

The traditional operating companies, Southern Power, and SEGCO, at December 31, 2012, owned and/or operated 33 hydroelectric generating stations, 32 fossil fuel generating stations, three nuclear generating stations, and 13 combined cycle/cogeneration stations, four solar facilities, one landfill gas facility, and one biomass 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	1,539,700	(4)
Hammond	Rome, GA	800,000	
Kraft	Port Wentworth, GA	281,136	(4)
McIntosh	Effingham County, GA	163,117	
McManus	Brunswick, GA	115,000	(4)
Mitchell	Albany, GA	125,000	
Scherer	Macon, GA	750,924	(5)
Wansley	Carrollton, GA	925,550	(6)
Yates	Newnan, GA	1,250,000	(4)
Georgia Power Total		9,110,427	
Crist	Pensacola, FL	970,000	
Daniel	Pascagoula, MS	500,000	(7)
Lansing Smith	Panama City, FL	305,000	
Scholz	Chattahoochee, FL	80,000	
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	(8)
Gaston Units 1-4	Wilsonville, AL		
SEGCO Total		1,000,000	(9)
Total Fossil Steam		20,540,465	

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Generating Station	Location	Nameplate Capacity (1)	
NUCLEAR STEAM			
Farley	Dothan, AL		
Alabama Power Total		1,720,000	
Hatch	Baxley, GA	899,612	(10)
Vogtle	Augusta, GA	1,060,240	(11)
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	59,100	(4)
Bowen	Cartersville, GA	39,400	(4)
Intercession City	Intercession City, FL	47,667	(12)
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	(13)
Robins	Warner Robins, GA	158,400	
Wansley	Carrollton, GA	26,322	(6)
Wilson	Augusta, GA	354,100	
Georgia Power Total		1,986,289	
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	(14)
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	(9)
Total Combustion Turbines		6,397,772	
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	(15)
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	(16)
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	(17)
Sinclair Dam	Milledgeville, GA	45,000	
Tallulah Falls	Clayton, GA	72,000	
Terrora	Clayton, GA	16,000	
Tugalo	Clayton, GA	45,000	

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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	
Southern Power Total		47,826	(18)
Total Solar		48,531	
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		45,739,788	

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) Plant Branch Units 1 and 2 are scheduled to be retired on December 31, 2013 and October 1, 2013, respectively. Georgia Power's 2013 IRP filing included Georgia Power's request to decertify 16 coal- and oil-fired units totaling 2,093 MWs. Georgia Power requested the decertification of Plant Boulevard Units 2 and 3 (28 MWs) upon approval of the 2013 IRP and the decertification of Plant Bowen Unit 6 (32 MWs) by April 16, 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 retired by April 16, 2015, the compliance date for the MATS rule. Georgia Power has also requested a revision to the decertification date of Plant Branch Unit 1 from December 31, 2013 to April 16, 2015. To allow for necessary transmission and reliability improvements, Georgia Power expects to seek a one-year extension of the MATS rule compliance date for Plant Kraft Units 1 through 4 (316 MWs) and to retire these units by April 16, 2016.
(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) Does not include nameplate capacity at Plant Eaton (67,500 KWs), which was retired on December 31, 2012.
(9) SEGCO is jointly-owned by Alabama Power and Georgia Power. See BUSINESS in Item 1 herein for additional information.
(10) Capacity shown is Georgia Power's portion (50.1%) of total plant capacity.
(11) Capacity shown is Georgia Power's portion (45.7%) of total plant capacity.
(12) 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. Progress Energy Florida operates the unit.
(13) Mitchell Unit 4C (39,400 KWs) was retired on March 26, 2012.
(14) Generation is dedicated to a single industrial customer.
(15) McDonough Unit 1 (245,000 KWs) was retired on February 29, 2012. McDonough-Atkinson Units 5 and 6 (1,680,000 KWs) were placed into service on April 26, 2012 and October 28, 2012, respectively.
(16) Capacity shown is Southern Power's portion (65%) of total plant capacity.
(17) Capacity shown is Georgia Power's portion (25.4%) of total plant capacity. OPC operates the plant.
(18) Capacity shown is Southern Power's portion (90%) of the total plant capacity.

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, 2012, the unamortized portion of this cost was approximately $16.8 million.

In conjunction with the Kemper IGCC, Mississippi Power will own 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 is scheduled to be placed in service in June 2013. The estimated capital cost of the mine is approximately $245 million, of which $163.3 million has been incurred through December 31, 2012. 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 2012, the maximum demand on the traditional operating companies, Southern Power, and SEGCO was 35,479,000 KWs and occurred on June 29, 2012. 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 MEAG Power, OPC, and SEPA. The reserve margin for the traditional operating companies, Southern Power, and SEGCO in

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2012 was 20.8%. 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 (MWs)	Alabama Power	Power South	Georgia Power	OPC	MEAG Power	Dalton	Progress Energy Florida	Southern Power	OUC	FMPA	KUA
Plant Miller Units 1 and 2	1,320	91.8 %	8.2 %	— %	— %	— %	— %	— %	— %	— %	— %	— %
Plant Hatch	1,796	—	—	50.1	30.0	17.7	2.2	—	—	—	—	—
Plant Vogtle Units 1 and 2	2,320	—	—	45.7	30.0	22.7	1.6	—	—	—	—	—
Plant Scherer Units 1 and 2	1,636	—	—	8.4	60.0	30.2	1.4	—	—	—	—	—
Plant Wansley	1,779	—	—	53.5	30.0	15.1	1.4	—	—	—	—	—
Rocky Mountain	848	—	—	25.4	74.6	—	—	—	—	—	—	—
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.

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 and steam heating mains 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.

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) Native Village of Kivalina and the City of Kivalina v. Exxon Mobile et al. (United States District Court for the Northern District of California)
See Note 3 to the financial statements of Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power under "Climate Change Litigation – Kivalina Case" in Item 8 herein for information.

(3) Comer et al. v. Murphy Oil USA, Inc. (United States District Court for the Southern District of Mississippi)
See Note 3 to the financial statements of Southern Company, Alabama Power, Georgia Power, Gulf Power, and Southern Power under "Climate Change Litigation – Hurricane Katrina Case" in Item 8 herein for information.

(4) 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 Georgia Power under "Retail Regulatory Matters – Nuclear Construction" in Item 8 herein for information.

(5) 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, 2012.

Thomas A. Fanning
Chairman, President, Chief Executive Officer, and Director
Age 55
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. He also served as Executive Vice President and Chief Financial Officer from May 2007 through January 2008.

Art P. Beattie
Executive Vice President and Chief Financial Officer
Age 58
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 56
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 43
Elected in 2012. President, Chief Executive Officer, and Director of Gulf Power since July 1, 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
Executive Vice President and Chief Operating Officer
Age 50
Elected in 2010. Executive Vice President and Chief Operating Officer since July 1, 2012. Previously served as President, Chief Executive Officer, and Director of Gulf Power from January 2011 through June 2012, Executive Vice President of External Affairs at Alabama Power from February 2008 through December 2010, and Senior Vice President and Counsel of Alabama Power from July 2006 through January 2008.

Edward Day, VI
President and Chief Executive Officer of Mississippi Power
Age 52
Elected in 2010. President, Chief Executive Officer, and Director of Mississippi Power since August 2010. Previously served as Executive Vice President for Engineering and Construction Services at Southern Company Generation, a business unit of Southern Company, from May 2003 to August 2010.

G. Edison Holland, Jr.
Executive Vice President, General Counsel, and Corporate Secretary
Age 60
Elected in 2001. Corporate Secretary since April 2005 and Executive Vice President and General Counsel since April 2001.

Stephen E. Kuczynski

President and Chief Executive Officer of Southern Nuclear
Age 50
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
Executive Vice President
Age 61
Elected in 1998. Executive Vice President since February 2002 and President, Chief Executive Officer, and Director of Alabama Power since October 2001.
Susan N. Story
Executive Vice President (to retire effective April 1, 2013)
Age 52
Elected in 2003. President and Chief Executive Officer of SCS since January 2011. Previously served as President, Chief Executive Officer, and Director of Gulf Power from April 2003 through December 2010.
Christopher C. Womack
Executive Vice President
Age 54
Elected in 2008. Executive Vice President and President of External Affairs since January 2009. Previously served as Executive Vice President of External Affairs of Georgia Power from March 2006 through December 2008.
The officers of Southern Company were elected for a term running from the first meeting of the directors following the last annual meeting (May 23, 2012) for one year or until their successors are elected and have qualified, except for Mr. Crosswhite whose election was effective July 1, 2012.

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, 2012.

Charles D. McCrary
President, Chief Executive Officer, and Director
Age 61
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 53
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 and as Vice President and Comptroller of Alabama Power from January 2005 to April 2008.

Zeke W. Smith
Executive Vice President
Age 53
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 57
Elected in 2001. Executive Vice President of the Customer Service Organization since February 2008. Previously served as Executive Vice President of External Affairs from 2001 through January 2008.

Theodore J. McCullough
Senior Vice President and Senior Production Officer
Age 49
Elected in 2010. Senior Vice President and Senior Production Officer since June 2010. Previously served as Vice President and Senior Production Officer of Gulf Power from September 2007 until June 2010.

The officers of Alabama Power were elected for a term running from the meeting of the directors held on April 27, 2012 for one year or until their successors are elected and have qualified.

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, 2012.

W. Paul Bowers
President, Chief Executive Officer, and Director
Age 56
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. He also served as Executive Vice President of Southern Company from May 2007 to February 2008 and as President of Southern Company Generation, a business unit of Southern Company, and Executive Vice President of SCS from May 2001 through January 2008.

W. Craig Barrs
Executive Vice President
Age 55
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, Vice President of Governmental and Regulatory Affairs from April 2008 to December 2008, and Vice President of the Coastal Region from August 2006 to March 2008.

Ronnie R. Labrato
Executive Vice President, Chief Financial Officer, and Treasurer (to retire effective March 31, 2013)
Age 59
Elected in 2009. Executive Vice President, Chief Financial Officer, and Treasurer since April 2009. Previously served as Vice President of Internal Auditing at SCS from April 2008 to March 2009 and Vice President and Chief Financial Officer of Gulf Power from July 2001 to March 2008.

Joseph A. Miller
Executive Vice President
Age 51
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 48
Elected in 2011. Executive Vice President of Customer Service and Operations since January 1, 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 52
Elected in 2008. Corporate Secretary since April 2011 and Senior Vice President, Chief Compliance Officer, and General Counsel since September 2008. Previously served as Vice President and Associate General Counsel for SCS from July 2004 to September 2008.

John L. Pemberton
Senior Vice President and Senior Production Officer
Age 42
Elected in 2012. Senior Vice President and Senior Production Officer since July 1, 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 16, 2012 for one year or until their successors are elected and have qualified, except for Mr. Pemberton, whose election was effective July 1, 2012.

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, 2012.

Edward Day, VI
President, Chief Executive Officer, and Director
Age 52
Elected in 2010. President, Chief Executive Officer, and Director since August 2010. Previously served as Executive Vice President for Engineering and Construction Services at Southern Company Generation, a business unit of Southern Company, from May 2003 to August 2010.

Thomas O. Anderson, IV
Vice President
Age 53
Elected in 2009. Vice President of Generation Development since July 2009. Previously served as Project Director, Mississippi Power Generation Development from March 2008 to July 2009; Project Manager, Southern Power Generation from June 2007 to March 2008; and Generation Development Manager, SCS Generation Development from September 1998 to June 2007.

John W. Atherton
Vice President
Age 52
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.

Moses H. Feagin
Vice President, Treasurer, and Chief Financial Officer
Age 48
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, and Comptroller of Mississippi Power from March 2005 to May 2008.

Jeff G. Franklin
Vice President
Age 45
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, Vice President of Sales from July 2008 to April 2009, and Vice President of the Northwest region from February 2005 to June 2008.

R. Allen Reaves
Vice President
Age 53
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 and Site Manager for Southern Power's Plant Franklin from March 2006 to September 2007.

Billy F. Thornton
Vice President
Age 52
Elected in 2012. Vice President of Legislative and Regulatory Affairs since October 22, 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 24, 2012 for one year or until their successors are elected and have qualified, except for Mr. Thornton, whose election was effective October 22, 2012.

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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
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
2011		
First Quarter	$38.79	$36.51
Second Quarter	40.87	37.43
Third Quarter	43.09	35.73
Fourth Quarter	46.69	41.00

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, 2013: 149,136
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	2012	2011
		(in thousands)	
Southern Company	First	$410,040	$385,010
	Second	426,891	402,165
	Third	429,711	405,879
	Fourth	426,450	408,294
Alabama Power	First	134,763	138,275
	Second	134,762	138,275
	Third	134,763	138,275
	Fourth	279,762	359,275
Georgia Power	First	227,075	224,025
	Second	227,075	224,025
	Third	227,075	224,025
	Fourth	302,075	424,025
Gulf Power	First	28,950	27,500
	Second	28,950	27,500
	Third	28,950	27,500
	Fourth	28,950	27,500
Mississippi Power	First	26,700	18,875
	Second	26,700	18,875

Third	26,700	18,875
Fourth	26,700	18,875

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In 2012 and 2011, Southern Power paid dividends to Southern Company as follows:

Registrant	Quarter	2012	2011
		(in thousands)	
Southern Power	First	$31,750	$22,800
	Second	31,750	22,800
	Third	31,750	22,800
	Fourth	31,750	22,800

The dividend paid per share of Southern Company's common stock was 47.25¢ for the first quarter 2012 and 49¢ each for the second, third, and fourth quarters of 2012. In 2011, Southern Company paid a dividend per share of 45.50¢ for the first quarter and 47.25¢ each for the second, third, and fourth quarters.

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

Southern Power's senior note indenture contains potential limitations on the payment of common stock dividends. At December 31, 2012, Southern Power 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

2012	Total Number of Shares Purchased (a)	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (a)
October 1 - October 30	4,575,956	$46.13	4,575,956	N/A
November 1 - November 30	2,296,351	44.52	2,296,351	N/A
December 1 - December 30	—	N/A	N/A	N/A
Total	6,872,307	$45.59	6,872,307	N/A

(a) In July 2012, Southern Company announced that it planned to use the proceeds received from stock options exercises during 2012 (including $317 million received through June 30, 2012) to repurchase shares to partially offset the incremental shares issued under its employee and director stock plans. In September 2012, Southern Company engaged an agent to repurchase shares of Southern Company common stock on an ongoing basis to partially offset the incremental shares issued under its employee and director stock plans. As of December 31, 2012, Southern Company had repurchased a total of 9,439,561 shares under this program. In January 2013, Southern Company announced that it plans to continue this program through 2015. Pursuant to approval by the Board of Directors, Southern Company may repurchase shares through open market purchases or privately negotiated transactions, in accordance with applicable securities laws.

Item 6. SELECTED FINANCIAL DATA

	Page
Southern Company. See "SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA"	II-116
Alabama Power. See "SELECTED FINANCIAL AND OPERATING DATA"	II-198
Georgia Power. See "SELECTED FINANCIAL AND OPERATING DATA"	II-282
Gulf Power. See "SELECTED FINANCIAL AND OPERATING DATA"	II-353
Mississippi Power. See "SELECTED FINANCIAL AND OPERATING DATA"	II-441
Southern Power. See "SELECTED FINANCIAL AND OPERATING DATA"	II-489

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.

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Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA
INDEX TO 2012 FINANCIAL STATEMENTS

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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, Mississippi Power, and Southern Power 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.

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-119 of this Form 10-K.

Georgia Power's Management's Report on Internal Control Over Financial Reporting is included on page II-201 of this Form 10-K.

Gulf Power's Management's Report on Internal Control Over Financial Reporting is included on page II-285 of this Form 10-K.

Mississippi Power's Management's Report on Internal Control Over Financial Reporting is included on page II-356 of this Form 10-K.

Southern Power's Management's Report on Internal Control Over Financial Reporting is included on page II-444 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 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, Mississippi Power's, or Southern 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 2012 that have materially affected or are reasonably likely to materially affect Southern Company's, Alabama Power's, Georgia Power's, Gulf Power's, Mississippi Power's, or Southern Power's internal control over financial reporting.

Item 9B. OTHER INFORMATION

On February 25, 2013, Gulf Power issued to Southern Company, in a private placement, 400,000 shares of Gulf Power's common stock, no par value, for an aggregate purchase price of $40,000,000. There were no underwriting discounts or commissions. The issuance to Southern Company was exempt from registration under the Securities Act of 1933, as amended (Act), pursuant to Section 4(2) of the Act because it was a transaction by an issuer that did not involve a public offering.

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THE SOUTHERN COMPANY
AND SUBSIDIARY COMPANIES
FINANCIAL SECTION

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Southern Company and Subsidiary Companies 2012 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 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, 2012.

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, 2012. 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, 2013

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, 2012 and 2011, 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, 2012. We also have audited the Company's internal control over financial reporting as of December 31, 2012, based on criteria established in Internal Control - Integrated Framework 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-47 to II-114) referred to above present fairly, in all material respects, the financial position of Southern Company and Subsidiary Companies as of December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, 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, 2012, based on the criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 27, 2013

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Southern Company and Subsidiary Companies 2012 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, fuel, capital expenditures, including new plants, and restoration following major storms. 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.

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 and constructing new 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, 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 2012 Peak Season EFOR was better than the target, excluding the impact of Hurricane Isaac in August 2012. 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 2012 was better than the target for these reliability measures.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Southern Company and Subsidiary Companies 2012 Annual Report

Southern Company's 2012 results compared with its targets for some of these key indicators are reflected in the following chart:

Key Performance Indicator	2012 Target Performance	2012 Actual Performance
System Customer Satisfaction	Top quartile in customer surveys	Top quartile
Peak Season System EFOR — fossil/hydro*	4.99% or less	2.81%
Basic EPS	$2.58 — $2.70	$2.70
EPS, excluding the MC Asset Recovery insurance settlement**		$2.68

*Excluding impact of Hurricane Isaac
**Southern Company filed an insurance claim in 2009 to recover a portion of the MC Asset Recovery settlement and received a nontaxable $25 million payment from its insurance provider on June 14, 2012. Additionally, legal fees related to this insurance settlement totaled approximately $6 million. As a result, the net reduction to expense for this insurance settlement was approximately $19 million. Southern Company management uses the non-generally accepted accounting principles (GAAP) measure of EPS, excluding the MC Asset Recovery insurance settlement, to evaluate the performance of Southern Company's ongoing business activities. Southern Company believes the presentation of this non-GAAP measure of earnings and EPS excluding the MC Asset Recovery insurance settlement 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 Note 3 to the financial statements under "Insurance Recovery" for additional information.

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance. The performance achieved in 2012 reflects the continued emphasis that management places on these indicators as well as the commitment shown by employees in achieving or exceeding management's expectations.

Earnings

Southern Company's net income after dividends on preferred and preference stock of subsidiaries was $2.35 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.

Southern Company's net income after dividends on preferred and preference stock of subsidiaries was $2.20 billion in 2011, an increase of $228 million, or 11.5%, from the prior year. The increase was primarily the result of increases in Georgia Power's retail base revenues as authorized under the 2010 Alternative Rate Plan for the years 2011 through 2013 (2010 ARP) and the recovery of financing costs through the Nuclear Construction Cost Recovery (NCCR) tariff. Also contributing to the increase were increases in energy and capacity revenues at Southern Power and a reduction in operations and maintenance expenses primarily at Alabama Power. The 2011 increase was partially offset by decreases in weather-related revenues due to closer to normal weather in 2011 compared to 2010, a decrease in the amortization of the regulatory liability related to other cost of removal obligations at Georgia Power, a decrease in wholesale revenues primarily at Alabama Power, and a reduction in allowance for funds used during construction (AFUDC) equity. Net income after dividends on preferred and preference stock of subsidiaries was $1.98 billion in

2010.
Basic EPS was $2.70 in 2012, $2.57 in 2011, and $2.37 in 2010. Diluted EPS, which factors in additional shares related to stock-based compensation, was $2.67 in 2012, $2.55 in 2011, and $2.36 in 2010. EPS for 2012 was negatively impacted by $0.05 per share as a result of an increase in the average shares outstanding.

Dividends
Southern Company has paid dividends on its common stock since 1948. Dividends paid per share of common stock were $1.9425 in 2012, $1.8725 in 2011, and $1.8025 in 2010. In January 2013, Southern Company declared a quarterly dividend of 49.00 cents per share. This is the 261st consecutive quarter that Southern Company has paid a dividend equal to or higher than the previous quarter. The Company targets a dividend payout ratio of approximately 70% to 75% of net income. For 2012, the actual payout ratio was 71.9%, while the payout ratio of net income excluding the MC Asset Recovery insurance settlement was 72.5%.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Southern Company and Subsidiary Companies 2012 Annual Report

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		
	2012	2011	2010
	(in millions)		
Electricity business	$2,321	$2,214	$1,991
Other business activities	29	(11)	(16)
Net income	$2,350	$2,203	$1,975

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	
	2012	2012	2011
	(in millions)		
Electric operating revenues	$16,478	$(1,109)	$213
Fuel	5,057	(1,205)	(437)
Purchased power	544	(64)	45
Other operations and maintenance	3,695	(147)	(63)
Depreciation and amortization	1,772	72	205
Taxes other than income taxes	912	13	32
Total electric operating expenses	11,980	(1,331)	(218)
Operating income	4,498	222	431
Allowance for equity funds used during construction	143	(10)	(41)
Interest income	22	3	(3)
Interest expense, net of amounts capitalized	820	17	(30)
Other income (expense), net	(57)	16	(15)
Income taxes	1,400	107	179
Net income	2,386	107	223
Dividends on preferred and preference stock of subsidiaries	65	—	—
Net income after dividends on preferred and preference stock of subsidiaries	$2,321	$107	$223

MANAGEMENT’S DISCUSSION AND ANALYSIS (continued)
Southern Company and Subsidiary Companies 2012 Annual Report

Electric Operating Revenues
Details of electric operating revenues were as follows:

	Amount 2012	2011
	(in millions)	
Retail — prior year	$15,071	$14,791
Estimated change in —		
Rates and pricing	296	793
Sales growth (decline)	39	38
Weather	(282)	(279)
Fuel and other cost recovery	(937)	(272)
Retail — current year	14,187	15,071
Wholesale revenues	1,675	1,905
Other electric operating revenues	616	611
Electric operating revenues	$16,478	$17,587
Percent change	(6.3)%	1.2%

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, as well as the collection of financing costs associated with the construction of two new nuclear generating units at Plant Vogtle (Plant Vogtle Units 3 and 4) through the NCCR tariff and demand-side management programs effective January 1, 2012, as approved by the Georgia Public Service Commission (PSC), and 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.
Retail revenues increased $280 million, or 1.9%, in 2011 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 2011 was primarily due to increases in Georgia Power's retail base revenues as authorized under the 2010 ARP, which became effective January 1, 2011. The increase in base revenues at Georgia Power also included the collection of financing costs associated with the construction of Plant Vogtle Units 3 and 4 through the NCCR tariff effective January 1, 2011. See "Allowance for Equity Funds Used During Construction" and "Interest Expense, Net of Amounts Capitalized" herein for additional information. Also contributing to the increase in rates and pricing in 2011 were revenues associated with Alabama Power's Rate CNP Environmental due to the completion of construction projects related to environmental mandates and the elimination of a tax-related adjustment under Alabama Power's rate structure.
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, unit power sales contracts, and short-term opportunity sales. Wholesale revenues from PPAs and unit power sales contracts 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.

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.

In 2011, wholesale revenues decreased $89 million, or 4.5%, as compared to the prior year due to decreased energy revenues. This decrease was primarily due to a decrease in wholesale revenues at Alabama Power due to the expiration of long-term unit power sales contracts in May 2010 and the capacity subject to those contracts being made available for retail service starting in June 2010, as well as lower energy and capacity revenues associated with the expiration of PPAs at Southern Power. The decrease was partially offset by higher energy and capacity revenues under new PPAs at Southern Power.

Revenues associated with PPAs and opportunity sales were as follows:

	2012	2011	2010
	(in millions)		
Other power sales —			
Capacity and other	$827	$767	$684
Energy	776	1,035	1,034
Total	$1,603	$1,802	$1,718

Kilowatt-hour (KWH) sales under unit power sales contracts decreased 65.2% and 69.6% in 2012 and 2011, respectively, as compared to the prior years. In addition, fluctuations in natural gas prices, which is the primary fuel source for unit power sales contracts, influence changes in energy sales. However, because the energy is generally sold at variable cost, fluctuations in energy sales have a minimal effect on earnings. The capacity and energy components of the unit power sales contracts were as follows:

	2012	2011	2010
	(in millions)		
Unit power sales —			
Capacity	$55	$53	$136
Energy	17	50	140
Total	$72	$103	$276

Other Electric Revenues

Other electric revenues increased $5 million, or 0.8%, and $22 million, or 3.7%, in 2012 and 2011, respectively, as compared to the prior years. Other electric revenues increased in 2012 primarily due to an increase in rents from electric property. The 2011 increase in other electric revenues was primarily a result of an increase in transmission revenues at Georgia Power.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Southern Company and Subsidiary Companies 2012 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 2012 and the percent change by year were as follows:

	Total KWHs 2012 (in billions)	Total KWH Percent Change 2012	Total KWH Percent Change 2011	Weather-Adjusted Percent Change 2012	Weather-Adjusted Percent Change 2011
Residential	50.4	(5.4)%	(7.7)%	1.1%	—%
Commercial	53.0	(1.6)	(2.9)	(0.2)	(0.3)
Industrial	51.7	0.2	3.2	0.2	3.3
Other	0.9	(1.8)	(0.8)	(1.4)	(0.7)
Total retail	156.0	(2.3)	(2.7)	0.4%	1.0%
Wholesale	27.6	(9.2)	(6.8)		
Total energy sales	183.6	(3.4)%	(3.4)%		

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 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 demand primarily in the residential class. Retail energy sales decreased 4.5 billion KWHs in 2011 as compared to the prior year. This decrease was primarily the result of closer to normal weather in 2011 compared to 2010, partially offset by an increase in industrial KWH sales. Increased demand in the primary metals and fabricated metals sectors was the main contributor to the increase in industrial KWH sales. The number of customers in 2011 was flat when compared to 2010.

Wholesale energy sales decreased 2.8 billion KWHs in 2012 and 2.2 billion KWHs in 2011 as compared to the prior years. The decrease in wholesale energy sales in 2012 was primarily related to lower customer demand resulting from milder weather in 2012. The decrease in wholesale energy sales in 2011 was primarily related to the expiration of long-term unit power sales contracts in May 2010 at Alabama Power and the capacity subject to those contracts being made available for retail service starting in June 2010. This decrease was partially offset by increased energy sales under new PPAs at Southern Power.

MANAGEMENT’S DISCUSSION AND ANALYSIS (continued)
Southern Company and Subsidiary Companies 2012 Annual Report

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 generation and purchased power by the electric utilities were as follows:

	2012	2011	2010
Total generation (billions of KWHs)	175	186	196
Total purchased power (billions of KWHs)	16	12	10
Sources of generation (percent) —			
Coal	38	52	58
Nuclear	18	16	15
Gas	42	30	25
Hydro	2	2	2
Cost of fuel, generated (cents per net KWH) —			
Coal	3.96	4.02	3.93
Nuclear	0.83	0.72	0.63
Gas	2.86	3.89	4.27
Average cost of fuel, generated (cents per net KWH)	2.93	3.43	3.50
Average cost of purchased power (cents per net KWH) *	4.45	6.32	6.98

* Average cost of purchased power includes fuel purchased by the electric utilities for tolling agreements where power is generated by the provider.

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.
In 2011, total fuel and purchased power expenses were $6.9 billion, a decrease of $392 million, or 5.4%, as compared to the prior year. This decrease was primarily the result of a $349 million decrease in the volume of KWHs generated and a $206 million decrease in the average cost of fuel and purchased power, partially offset by a $163 million increase in the volume of KWHs purchased.
From an overall global market perspective, coal prices decreased from levels experienced in 2011 due to lower demand. In the U.S., this decrease was due primarily to relatively lower domestic natural gas prices that contributed to displacement of coal generation by natural gas-fueled generating units. Lower domestic natural gas prices in 2012 were driven by continued robust supplies, including production from shale gas, and only modest increases in overall U.S. consumption.
Uranium prices began to decrease during the second half of 2012 as extended reactor shutdowns in Europe and Asia caused global demand for uranium to drop below the level of previous years, while production increased. Changes in the cost of fuel for nuclear generation tend to lag behind changes in uranium market prices. Even though uranium prices decreased slightly during 2012, the cost of fuel for nuclear generation increased in 2012, reflecting the higher uranium prices from previous years when the uranium was 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 – 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.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Southern Company and Subsidiary Companies 2012 Annual Report

Fuel
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.
In 2011, fuel expense was $6.3 billion, a decrease of $437 million, or 6.5%, as compared to the prior year. The decrease was primarily due to an 8.9% decrease in the average cost of natural gas per KWH generated and lower demand primarily due to closer to normal weather in 2011 compared to 2010.
Purchased Power
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.
In 2011, purchased power expense was $608 million, an increase of $45 million, or 8.0%, as compared to the prior year. The increase was due to a 23.9% increase in the volume of KWHs purchased as the market cost of available energy was lower than the marginal cost of generation available, partially offset by a 9.5% decrease in the average cost per KWH purchased.
Energy purchases will vary depending on demand for energy within the Southern Company system's service territory, the market prices of wholesale energy as compared to the cost of the Southern Company system's generation, and the availability of the Southern Company system's generation.
Other Operations and Maintenance Expenses
Other operations and maintenance expenses were $3.7 billion and $3.8 billion, decreasing $147 million, or 3.8%, and $63 million, or 1.6%, in 2012 and 2011, respectively, as compared to the prior years. Discussion of significant variances for components of other operations and maintenance expenses follows.
Other production expenses at fossil, hydro, and nuclear plants decreased $110 million in 2012 and increased $2 million in 2011 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. 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 FINANCIAL CONDITION AND LIQUIDITY – "Purchase of the Plant Daniel Combined Cycle Generating Units" herein for additional information. Other production expenses increased in 2011 mainly due to a $29 million increase in commodity and labor costs and a $26 million increase in outage and maintenance costs. These increases were largely offset by a decrease in nuclear outage expense at Alabama Power, primarily related to the change in the nuclear maintenance outage accounting process. As a result, Alabama Power did not recognize any nuclear maintenance outage expenses in 2011, reducing nuclear production expense by approximately $50 million as compared to 2010. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Alabama Power – Nuclear Outage Accounting Order" herein for additional information.
Transmission and distribution expenses decreased $75 million and $80 million in 2012 and 2011, respectively, 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 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). Transmission and distribution expenses

decreased in 2011 primarily due to reductions in spending related to vegetation management and a reduction in accruals to the NDR at Alabama Power. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Alabama Power – Natural Disaster Reserve" herein for additional information.

Customer accounts, sales, and service expenses decreased $20 million in 2012 and increased $33 million in 2011 as compared to the prior years. Customer accounts, sales, and service expenses decreased in 2012 primarily due to a decrease in uncollectible account expense at Georgia Power. Customer accounts, sales, and service expenses increased in 2011 primarily due to a $24 million increase in customer service expense primarily related to new demand side management programs at Georgia Power and a $9 million increase in records and collection expense.

Administrative and general expenses increased $58 million in 2012 and decreased $18 million in 2011 as compared to the prior years. Administrative and general expenses increased in 2012 primarily as a result of an increase in pension costs. Administrative and general expenses decreased in 2011 primarily as a result of a $10 million decrease in property insurance cost and a $7 million decrease in injuries and damages reserve costs.

MANAGEMENT’S DISCUSSION AND ANALYSIS (continued)
Southern Company and Subsidiary Companies 2012 Annual Report

Depreciation and Amortization

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 the 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" for additional information.

Depreciation and amortization increased $205 million, or 13.7%, in 2011 as compared to the prior year primarily as a result of a $142 million decrease in the amortization of the regulatory liability related to other cost of removal obligations at Georgia Power as authorized by the Georgia PSC and additional depreciation on plant in service related to environmental, transmission, and distribution projects. See Note 3 to the financial statements under "Retail Regulatory Matters – Georgia Power – Rate Plans" for additional information regarding Georgia Power's cost of removal amortization.

See Note 1 to the financial statements under "Depreciation and Amortization" for additional information.

Taxes Other Than Income 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. Taxes other than income taxes increased $32 million, or 3.7%, in 2011 compared to the prior year primarily due to increases in property taxes and municipal franchise fees at Georgia Power and increases in state and municipal public utility license tax bases at Alabama Power. Increases in franchise fees are associated with increases in revenues from energy sales.

Allowance for Equity Funds Used During Construction

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 construction work in progress (CWIP) related to Mississippi Power's integrated coal gasification combined cycle facility under construction in Kemper County, Mississippi (Kemper IGCC), which began construction in 2010.

AFUDC equity decreased $41 million, or 21.1%, in 2011 as compared to the prior year primarily due to the inclusion of Georgia Power's construction costs for Plant Vogtle Units 3 and 4 in rate base effective January 1, 2011 in accordance with the Georgia Nuclear Energy Financing Act and a Georgia PSC order. This action reduced the amount of AFUDC capitalized, with an offsetting increase in operating revenues through the NCCR tariff. See Note 3 to the financial statements under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" for additional information. Also contributing to the decrease was the completion of construction projects related to environmental mandates at Alabama Power. The 2011 decrease was partially offset by CWIP related to Mississippi Power's Kemper IGCC.

Interest Expense, Net of Amounts Capitalized

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 (DOR), 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.

Total interest charges and other financing costs decreased $30 million, or 3.6%, in 2011 as compared to the prior year primarily due to a reduction of $23 million in interest expense at Georgia Power related to the settlement of litigation

with the Georgia DOR and lower interest expense on existing variable rate pollution control revenue bonds at Georgia Power. The decrease was partially offset by a reduction in AFUDC debt at Georgia Power due to the inclusion of construction costs for Plant Vogtle Units 3 and 4 in rate base.
Other Income (Expense), Net
Other income (expense), net increased $16 million, or 21.9%, in 2012 and decreased $15 million, or 25.9%, in 2011 as compared to the prior years primarily due to a make-whole premium payment in connection with the early redemption of senior notes at Southern Power in 2011.

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Income Taxes

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.

Income taxes increased $179 million, or 16.1%, in 2011 as compared to the prior year primarily due to higher pre-tax earnings, a decrease in 2010 in uncertain tax positions at Georgia Power related to state income tax credits, and a reduction in AFUDC equity, which is non-taxable.

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. 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	
	2012	2012	2011
	(in millions)		
Operating revenues	$59	$(11)	$(12)
Other operations and maintenance	96	—	(9)
MC Asset Recovery litigation settlement	(19)	(19)	—
Depreciation and amortization	15	(2)	(1)
Taxes other than income taxes	2	—	—
Total operating expenses	94	(21)	(10)
Operating income (loss)	(35)	10	(2)
Interest income	18	16	—
Equity in income (losses) of unconsolidated subsidiaries	(2)	—	—
Leveraged lease income (losses)	21	(4)	7
Other income (expense), net	—	11	6
Interest expense	39	(15)	(8)
Income taxes	(66)	8	14
Net income (loss)	$29	$40	$5

Operating Revenues

Southern Company's non-electric operating revenues from these other business activities decreased $11 million, or 15.7%, and $12 million, or 14.6%, in 2012 and 2011, 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

In 2012, the change in other operations and maintenance expenses for these other businesses was not material. Other operations and maintenance expenses for these other businesses decreased $9 million, or 8.6%, in 2011 as compared to the prior year. The decrease in 2011 was primarily the result of lower administrative and general expenses.

MC Asset Recovery Insurance Settlement

On June 14, 2012, Southern Company received an insurance recovery related to the litigation settlement with MC Asset Recovery, LLC, which resulted in income of $19 million. See Note 3 to the financial statements under "Insurance Recovery" for additional information.

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Interest Income

Interest income for these other businesses increased $16 million in 2012 as compared to the prior year primarily due to the conclusion of certain federal income tax audits. In 2011, the change in interest income for these other businesses was not material.

Leveraged Lease Income (Losses)

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. The change in leveraged lease income (losses) in 2012 compared to 2011 was not material. Leveraged lease income (losses) increased $7 million, or 38.9%, in 2011 as compared to the prior year primarily as a result of changes in the average leveraged lease investment balance. See FUTURE EARNINGS POTENTIAL – "Investments in Leveraged Leases" herein for additional information.

Other Income (Expense), Net

Other income (expense), net for these other businesses increased $11 million in 2012 and $6 million in 2011 as compared to the prior years primarily as a result of decreases in the amount of charitable contributions made by the parent company.

Interest Expense

Total interest charges and other financing costs for these other businesses decreased $15 million, or 27.8%, in 2012 and $8 million, or 12.9%, in 2011 as compared to the prior years primarily due to lower interest rates on existing debt.

Income Taxes

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. Income taxes for these other business increased $14 million, or 15.9%, in 2011 as compared to the prior year primarily as a result of lower pre-tax losses and a prior year state tax adjustment related to leveraged leases.

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 ongoing construction projects, including construction of generating facilities. 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 neighboring 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 economic conditions impact sales for the traditional operating companies and Southern Power, and 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 2012, the Southern Company system generating capacity increased 2,184 megawatts (MWs), net of retirements of 352 MWs, due to the completion of Plant McDonough-Atkinson Units 5 and 6, the completion of a biomass generating plant, the completion of Plant Cleveland County Units 1 through 4, and the acquisition of three solar photovoltaic facilities. In general, the Southern Company system has constructed or acquired new generating capacity only after entering into long-term capacity contracts for the new facilities or to meet requirements of the Southern Company system's regulated retail markets, both of which are optimized by limited energy trading activities. See "Construction Program" herein for additional information.

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, 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

In 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including Alabama Power and Georgia Power, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. The EPA alleged NSR violations at five coal-fired generating facilities operated by Alabama Power, including a unit co-owned by Mississippi Power, and three coal-fired generating facilities operated by Georgia Power, including a unit co-owned by Gulf Power. The civil action sought penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. The case against Georgia Power (including claims related to the unit co-owned by Gulf Power) was administratively closed in 2001 and has not been reopened. After Alabama Power was dismissed from the original action, the EPA filed a separate action in 2001 against Alabama Power (including claims related to the unit co-owned by Mississippi Power) in the U.S. District Court for the Northern District of Alabama.

In 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree, resolving claims relating to the alleged NSR violations at Plant Miller. In 2010, the EPA dismissed five of its eight remaining claims against Alabama Power, leaving only three claims, including one relating to the unit co-owned by Mississippi Power. In March 2011, the U.S. District Court for the Northern District of Alabama granted Alabama Power summary judgment on all remaining claims and dismissed the case with prejudice. That judgment is on appeal to the U.S. Court of Appeals for the Eleventh Circuit. On February 23, 2012, the EPA filed a motion in the U.S. District Court for the Northern District of Alabama seeking vacatur of the judgment and recusal of the judge in the case involving Alabama Power.

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.

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Climate Change Litigation
Kivalina Case
In 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs allege that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that some of the defendants (including Southern Company) acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. In 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case. On September 21, 2012, the U.S. Court of Appeals for the Ninth Circuit upheld the U.S. District Court for the Northern District of California's dismissal of the case. On November 27, 2012, the U.S. Court of Appeals for the Ninth Circuit denied the plaintiffs' request for review of the decision. On February 25, 2013, the plaintiffs filed a petition for writ of certiorari with the U.S. Supreme Court. Southern Company believes that these claims are without merit. The ultimate outcome of this matter cannot be determined at this time.
Hurricane Katrina Case
In 2005, immediately following Hurricane Katrina, a lawsuit was filed in the U.S. District Court for the Southern District of Mississippi by Ned Comer on behalf of Mississippi residents seeking recovery for property damage and personal injuries caused by Hurricane Katrina. In 2006, the plaintiffs amended the complaint to include Southern Company and many other electric utilities, oil companies, chemical companies, and coal producers. The plaintiffs allege that the defendants contributed to climate change, which contributed to the intensity of Hurricane Katrina. In 2007, the U.S. District Court for the Southern District of Mississippi dismissed the case. On appeal to the U.S. Court of Appeals for the Fifth Circuit, a three-judge panel reversed the U.S. District Court for the Southern District of Mississippi, holding that the case could proceed, but, on rehearing, the full U.S. Court of Appeals for the Fifth Circuit dismissed the plaintiffs' appeal, resulting in reinstatement of the decision of the U.S. District Court for the Southern District of Mississippi in favor of the defendants. In May 2011, the plaintiffs filed an amended version of their class action complaint, arguing that the earlier dismissal was on procedural grounds and under Mississippi law the plaintiffs have a right to re-file. The amended complaint was also filed against numerous chemical, coal, oil, and utility companies, including Alabama Power, Georgia Power, Gulf Power, and Southern Power. On March 20, 2012, the U.S. District Court for the Southern District of Mississippi dismissed the plaintiffs' amended complaint. On April 16, 2012, the plaintiffs appealed the case to the U.S. Court of Appeals for the Fifth Circuit. Southern Company believes that these claims are without merit. The ultimate outcome of this matter 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 2012, the traditional operating companies had invested approximately $8.7 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $340 million, $300 million, and $500 million for 2012, 2011, and 2010, respectively. The Southern Company system expects that capital expenditures to comply with existing statutes and regulations, including capital expenditures and compliance costs associated with the EPA's final

Mercury and Air Toxics Standards (MATS) rule, will be a total of approximately $3.6 billion from 2013 through 2015, with annual totals of approximately $1.0 billion, $1.5 billion, and $1.1 billion for 2013, 2014, and 2015, respectively.

The Southern Company system continues to monitor the development of the EPA's proposed water and coal combustion byproducts rules and to evaluate compliance options. Based on its preliminary analysis and an assumption that coal combustion byproducts 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 2013 through 2015. The ultimate capital expenditures and compliance costs with respect to these proposed rules, including additional expenditures required after 2015, 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 Byproducts" 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. The impact of SEGCO's ultimate compliance strategy on such PPA costs cannot be determined at this time; however, if such 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 herein for additional information.

Compliance with any new federal or state legislation or regulations relating to air quality, water, coal combustion byproducts, 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 $7.6 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 air quality standard. In 2008, the EPA adopted a more stringent eight-hour ozone National Ambient Air Quality Standard, which it began to implement in September 2011. On May 21, 2012, the EPA published its final determination of nonattainment areas based on the 2008 eight-hour ozone air quality standards. 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 National Ambient Air Quality Standards and, in January 2013, the EPA officially redesignated the Birmingham area as attainment under both the annual and 24-hour standards. Redesignation requests for nonattainment areas 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 National Ambient Air Quality Standard for sulfur dioxide (SO_2), including the establishment of a new one-hour standard, became effective in 2010 (SO_2 Rule). The EPA plans to issue area designations under this new standard in June 2013, and areas within the Southern Company system's service territory could ultimately be designated as nonattainment. Implementation of the revised SO_2 standard could require additional reductions in SO_2 emissions and increased compliance and operational costs.

Revisions to the National Ambient Air Quality Standard for nitrogen dioxide (NO_2), which established a new one-hour standard, became effective in 2010. On February 29, 2012, the new NO_2 standard became effective. The EPA designated the entire country as "unclassifiable/attainment" under the new standard, with no nonattainment areas designated. However, the new NO_2 standard could result in significant additional compliance and operational costs for units that require new source permitting.

In 2008, the EPA approved a revision to Alabama's State Implementation Plan (SIP) requirements related to opacity, which granted some flexibility to affected sources while requiring compliance with Alabama's stringent opacity limits through use of continuous opacity monitoring system data. In April 2011, the EPA attempted to rescind its previous approval of the Alabama SIP revision. This decision impacts facilities operated by Alabama Power, including units co-owned by Mississippi Power. Alabama Power filed an appeal of that decision with the U.S. Court of Appeals for the Eleventh Circuit. The EPA's rescission has affected unit availability and increased maintenance and compliance costs. Unless the court resolves Alabama Power's appeal in its favor, the EPA's rescission will continue to affect Alabama Power's operations.

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 August 2011, the EPA adopted the Cross State Air Pollution Rule (CSAPR) to replace CAIR effective January 1, 2012. However, in December 2011, the U. S. Court of Appeals for the District of Columbia Circuit stayed the rule and, on August 21, 2012, vacated CSAPR in its entirety and directed the EPA to continue to administer CAIR pending the EPA's development of a valid replacement. On January 24, 2013, the U.S. Court of Appeals for the District of Columbia Circuit denied requests by the EPA and other parties for rehearing.

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 (BART) 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 2005, the EPA determined that compliance with CAIR satisfies BART obligations under CAVR, but, on June 7, 2012, the EPA issued a final rule replacing CAIR with CSAPR as an alternative means of satisfying BART obligations. The vacatur of CSAPR creates additional uncertainty with respect to whether additional controls may be required for CAVR and BART compliance.

On February 16, 2012, the EPA published the final 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, unless a one-year compliance extension is granted by the state or local air permitting agency.

Numerous petitions for administrative reconsideration of the MATS rule, including a petition by Southern Company and its subsidiaries, have been filed with the EPA. On November 30, 2012, the EPA proposed a reconsideration of certain new source and startup/shutdown issues. The EPA plans to complete its reconsideration rulemaking by March 2013. Challenges to the final rule have also been filed in the U.S. District Court for the District of Columbia by numerous states, environmental organizations, industry groups, and others.

On August 29, 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 January 31, 2013, the EPA published the final Industrial Boiler Maximum Achievable Control Technology (IB MACT) rule establishing emissions limits and/or work practice standards for various hazardous air pollutants emitted from industrial boilers, including biomass boilers and start-up boilers. Compliance for existing sources will be required by early 2016. Compliance for new sources will begin upon startup. Georgia Power is evaluating the impact of this final rule and other environmental regulations on the possible conversion of Plant Mitchell Unit 3 from coal to biomass.

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. If finalized as proposed, this new requirement could result in significant additional compliance and operational costs.

The Southern Company system has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the existing and new environmental requirements discussed above. The impacts of the eight-hour ozone, fine particulate matter, SO_2 and NO_2 standards, CAIR and any future replacement rule, CAVR, the MATS rule, the NSPS for CTs, the IB MACT rule, 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

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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 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 December 31, 2015. The State of Georgia also adopted a companion rule that requires a 95% reduction in SO_2 emissions from the controlled units on the same or similar timetable. Through December 31, 2012, Georgia Power had installed the required controls on 11 of its largest coal-fired generating units and is in the process of installing the required controls on two additional units. On February 21, 2013, the State of Georgia released proposed revisions for both the Multi-Pollutant Rule and the SO_2 Rule revising the compliance dates for those units yet to be controlled to make them consistent with the April 2015 compliance date for the MATS rule. According to the State of Georgia, the proposed revisions would also allow the units at Plant Yates to use natural gas as the primary fuel as an alternative to installing controls under the Multi-Pollutant Rule. The revisions to the Multi-Pollutant Rule and the SO_2 Rule are expected to be finalized in April 2013. The ultimate outcome of these matters cannot be determined at this time.

Water Quality

In April 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 has entered into an amended settlement agreement to extend the deadline for issuing a final rule until June 27, 2013. If finalized as proposed, some of the facilities of Southern Company's subsidiaries may be subject to 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. The ultimate outcome of this rulemaking will depend on the final rule and the outcome of any legal challenges and cannot be determined at this time.

The EPA has announced its determination that revision of the current effluent guidelines for steam electric power plants is warranted and has stated that it intends to propose such revisions by April 2013 and finalize the revisions by May 2014. New advanced wastewater treatment requirements are expected and may result in the installation of additional controls on certain of the facilities of Southern Company's subsidiaries, which could result in significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. The impact of the revised guidelines will depend on the specific technology requirements of the final rule and, therefore, cannot be determined at this time.

Coal Combustion Byproducts

The traditional operating companies currently operate 22 electric generating plants with on-site coal combustion byproducts storage facilities. In addition to on-site storage, the traditional operating companies also sell a portion of their coal combustion byproducts to third parties for beneficial reuse. Historically, individual states have regulated coal combustion byproducts and the states in the Southern Company system's service territory each have their own regulatory parameters. 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 byproducts, 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 byproducts:

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 byproducts 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 byproducts.

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 byproducts could have a material impact on the generation, management, beneficial use, and disposal of such byproducts. 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. 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 April 13, 2012, the EPA published proposed regulations to establish standards of performance for greenhouse gas emissions from new fossil fuel steam electric generating units. The EPA has also announced plans to develop federal guidelines for states to establish greenhouse gas emissions performance standards for existing sources. The impact of this rulemaking will depend on the scope and specific requirements of the final rule and the outcome of any legal challenges and, therefore, cannot be determined at this time.

Although the outcome of federal, state, and international initiatives 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 a significant number 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 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.

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 Southern Company system's 2011 greenhouse gas emissions were approximately 125 million metric tons of carbon dioxide equivalent. The preliminary estimate of the Southern Company system's 2012 greenhouse gas emissions on the same basis is approximately 98 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, which is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units.

PSC Matters
Alabama Power
Retail Rate Adjustments
In July 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 April 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%. Retail rates remain unchanged when the retail return on common equity (ROE) is projected to be between 13.0% and 14.5%. If Alabama Power's actual retail ROE 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 ROE fall below the allowed equity return range.

In 2011 and 2012, retail rates under Rate RSE remained unchanged from 2010. On November 30, 2012, Alabama Power made its Rate RSE submission to the Alabama PSC of projected data for calendar year 2013; projected earnings were within the specified return range, and, therefore, retail rates under Rate RSE remained unchanged for 2013. Under the terms of Rate RSE, the maximum possible increase for 2014 is 5.00%. However, Alabama Power is working with the Alabama PSC to develop a plan that will potentially preclude the need for a Rate RSE increase in 2014. The ultimate outcome of this matter cannot be determined at this time.

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). Effective April 2011, Rate CNP PPA was reduced by approximately $5 million annually. On March 6, 2012, 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, 2012 through March 31, 2013. It is anticipated that no adjustment will be made to Rate CNP PPA in 2013. As of December 31, 2012, Alabama Power had an under recovered certificated PPA balance of $9 million, $7 million of which is included in deferred under recovered regulatory clause revenues and $2 million of which is included in under recovered regulatory clause revenues in the balance sheet.

On September 17, 2012, the Alabama PSC approved and certificated a PPA for the purchase of approximately 200 MWs of the approximately 400 MWs of energy from wind-powered generating facilities and all associated environmental attributes, including renewable energy credits. The terms of this PPA and a previously approved and certificated PPA 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, to third parties. Approximately 200 MWs of energy from wind-powered generating facilities was operational in December 2012.

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 to recover environmental costs in 2011 or 2012. On November 26, 2012, 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 less than $1 million, which is to be recovered in the billing months of January 2013 through December 2013. On December 4, 2012, the Alabama PSC issued a consent order that Alabama Power leave in effect for 2013 the factors associated with Alabama Power's environmental compliance costs for the year 2012. Any unrecovered amounts associated with 2013 will be reflected in the 2014 filing. As of December 31, 2012, Alabama

Power had an under recovered environmental clause balance of $21 million which is included in under recovered regulatory clause revenues in the balance sheet.

Environmental Accounting Order

Proposed and final environmental regulations could result in significant additional compliance costs that could affect future unit retirement and replacement decisions. In September 2011, the Alabama PSC approved an order allowing for the establishment of a regulatory asset to record the unrecovered investment costs associated with any such decisions, including the unrecovered plant asset balance and the unrecovered costs associated with site removal and closure. 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

On November 6, 2012, the Alabama PSC approved an accounting order for certain compliance-related operation and maintenance expenditures for the years 2013 through 2017, as well as the incremental increase in operation expense related to pension cost for 2013. Under the accounting order, expenses from January 2013 through December 2017 related to compliance with standards addressing Critical Infrastructure Protection issued by the North American Electric Reliability Corporation and cyber security requirements issued by the Nuclear Regulatory Commission (NRC) will be deferred to a regulatory asset account and amortized over a three-year period beginning in January 2015. Expenses from January 2013 through December 2017 related to compliance with NRC guidance addressing the readiness at nuclear facilities within the U.S., as prompted by the earthquake and tsunami that struck Japan in March 2011, also will be deferred as a regulatory asset and recovered over the same amortization period. The compliance-related expenses to be afforded regulatory asset treatment over the five-year period are currently estimated to be approximately $43 million. See "Other Matters" herein for information regarding the NRC's guidance issued as a result of the earthquake and tsunami that struck Japan in 2011. In addition, the accounting order authorizes Alabama Power to defer an incremental increase in its pension cost for 2013. That increased pension cost is estimated to be approximately $17 million. During 2013, the actual incremental increase will be deferred to a regulatory asset account and will be amortized over a three-year period beginning in January 2015. Pursuant to the accounting order, Alabama Power has the ability to accelerate the amortization of the regulatory assets.

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. 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.

During the first half of 2011, multiple storms caused varying degrees of damage to Alabama Power's transmission and distribution facilities. The most significant storms occurred in April 2011, causing over 400,000 of Alabama Power's 1.4 million customers to be without electrical service. The cost of repairing the damage to facilities and restoring electrical service to customers as a result of these storms was $42 million for operations and maintenance expenses and $161 million for capital-related expenditures.

In accordance with the order that was issued by the Alabama PSC in July 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, 2012 and December 31, 2011 were approximately $103 million and $110 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 2010, the Alabama PSC approved a change to the nuclear maintenance outage accounting process associated with routine refueling activities. Previously, Alabama Power accrued nuclear outage operations and maintenance expenses for the two units at Plant Farley during the 18-month cycle for the outages. In accordance with the 2010 order, nuclear outage expenses are deferred when the charges actually occur and then amortized over the subsequent 18-month period.

The initial result of implementation of the accounting order was that no nuclear maintenance outage expenses were recognized from January 2011 through December 2011, which decreased nuclear outage operations and maintenance expenses in 2011 from 2010 by approximately $50 million. During the fall of 2011, approximately $38 million of actual nuclear outage expenses associated with one unit at Plant Farley was deferred to a regulatory asset account; beginning in January 2012, these deferred costs are being amortized to nuclear operations and maintenance expenses over an 18-month period. During the spring of 2012, approximately $31 million of actual nuclear outage expenses associated with the second unit at Plant Farley was deferred to a regulatory asset account; beginning in July 2012, these deferred costs are being amortized to nuclear operations and maintenance expenses 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 existing order.

Georgia Power

Rate Plans

The economic recession significantly reduced Georgia Power's revenues upon which retail rates were set by the Georgia PSC for 2008 through 2010 (2007 Retail Rate Plan). In 2009, despite stringent efforts to reduce expenses, Georgia Power's projected retail ROE for both 2009 and 2010 was below 10.25%. However, in lieu of a full base rate case to increase customer rates as allowed under the 2007 Retail Rate Plan, in 2009, the Georgia PSC approved Georgia Power's request for an accounting order. Under the terms of the accounting order, Georgia Power could amortize up to $108 million of the regulatory liability related to other cost of removal obligations in 2009 and up to $216 million in 2010, limited to the amount needed to earn no more than a 9.75% and 10.15% retail ROE in 2009 and 2010, respectively. For the years ended December 31, 2009 and 2010, Georgia Power amortized $41 million and $174 million, respectively, of the regulatory liability related to other cost of removal obligations.

In 2010, the Georgia PSC approved the 2010 ARP, which became effective January 1, 2011. The terms of the 2010 ARP reflect a settlement agreement among Georgia Power, the Georgia PSC Public Interest Advocacy Staff, and eight other intervenors. Under the terms of the 2010 ARP, Georgia Power is amortizing approximately $92 million of its remaining regulatory liability related to other cost of removal obligations over the three years ending December 31, 2013.

Also under the terms of the 2010 ARP, effective January 1, 2011, Georgia Power increased its (1) traditional base tariff rates by approximately $347 million; (2) Demand-Side Management (DSM) tariff rates by approximately $31 million; (3) environmental compliance cost recovery tariff rate by approximately $168 million; and (4) Municipal Franchise Fee (MFF) tariff rate by approximately $16 million, for a total increase in base revenues of approximately $562 million.

Under the 2010 ARP, the following additional base rate adjustments have been made to Georgia Power's tariffs in 2012 and 2013:

- Effective January 1, 2012 and 2013, the DSM tariffs increased by $17 million and $14 million, respectively;
- Effective April 1, 2012 and January 1, 2013, the traditional base tariffs increased by an estimated $122 million and $58 million, respectively, to recover the revenue requirements for Plant McDonough-Atkinson Units 4, 5, and 6 for the period through December 31, 2013; and
- The MFF tariff increased consistently with the adjustments above, as well as those related to the interim fuel rider and NCCR tariff adjustments described in Note 3 to the financial statements under "Retail Regulatory Matters – Georgia Power – Fuel Cost Recovery" and "Retail Regulatory Matters – Georgia Power – Nuclear Construction."

Under the 2010 ARP, Georgia Power's allowed retail ROE is set at 11.15%, and earnings will be evaluated against a retail ROE range of 10.25% to 12.25%. Two-thirds of any earnings above 12.25% will be directly refunded to customers, with the remaining one-third retained by Georgia Power. There were no refunds related to earnings for 2011 or 2012. Georgia Power is required to file a general base rate case by July 1, 2013, in response to which the Georgia PSC would be expected to determine whether the 2010 ARP should be continued, modified, or discontinued.

Integrated Resource Plans

See "Environmental Matters – Environmental Statutes and Regulations – Air Quality," "– Water Quality," and "– Coal Combustion Byproducts" 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 guidelines for steam electric power plants, and additional regulation of coal combustion byproducts; 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 the 2010 ARP.

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On March 20, 2012, the Georgia PSC approved Georgia Power's request to decertify and retire Plant Branch Units 1 and 2 as of December 31, 2013 and October 31, 2013, the compliance dates for the respective units under the Georgia Multi-Pollutant Rule, and an oil-fired unit at Plant Mitchell as of March 26, 2012, as requested in the 2011 Integrated Resource Plan (IRP). The Georgia PSC also approved three PPAs totaling 998 MWs with Southern Power for capacity and energy that will commence in 2015 and end in 2030. On November 21, 2012, the FERC accepted the PPAs.

Separately, on March 20, 2012, the Georgia PSC certified 495 MWs of wholesale capacity to be returned to retail service in 2015 and 2016 under a 2010 agreement, subject to the decertification of any related generating units including 243 MWs of the 16 units described below.

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.

Georgia Power requested the decertification of Plant Boulevard Units 2 and 3 (28 MWs) upon approval of the 2013 IRP and the decertification of Plant Bowen Unit 6 (32 MWs) by April 16, 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 retired by April 16, 2015, the compliance date of the MATS rule. Georgia Power has also requested a revision to the decertification date of Plant Branch Unit 1 from December 31, 2013 to April 16, 2015. To allow for necessary transmission reliability improvements, Georgia Power expects to seek a one-year extension of the MATS rule compliance date for Plant Kraft Units 1 through 4 (316 MWs) and to retire these units by April 16, 2016.

The filing also included Georgia Power's request to switch the primary fuel source for Plant Yates Units 6 and 7 from coal to natural gas. Additionally, Georgia Power plans to switch the primary fuel source for Plant McIntosh Unit 1 from Central Appalachian coal to Powder River Basin (PRB) coal following further evaluation, including a successful test burn of the PRB fuel.

Under the terms of the 2010 ARP, any costs associated with changes to Georgia Power's approved environmental operating or capital budgets resulting from new or revised environmental regulations through 2013 that are approved by the Georgia PSC in connection with an updated IRP will be deferred as a regulatory asset to be recovered over a time period deemed appropriate by the Georgia PSC. In connection with the retirement decisions, Georgia Power reclassified the retail portion of the net carrying value of Plant Branch Units 1 through 4 from plant in service, net of depreciation, to other utility plant, net. Georgia Power is continuing to depreciate these units using the current composite straight-line rates previously approved by the Georgia PSC. Upon actual retirement, the Georgia PSC approved the continued deferral and amortization of the remaining net carrying values for Plant Branch Units 1 and 2 in its order for the 2011 IRP and Georgia Power has requested similar treatment for Plant Branch Units 3 and 4 in the 2013 IRP. Georgia Power also reclassified the CWIP balances totaling $65 million related to environmental controls for Plant Branch Units 1 through 4 and Plant Yates Units 6 and 7 that will not be completed as a result of the retirement decisions to regulatory assets and ceased accruing AFUDC. The Georgia PSC approved a three-year amortization period beginning January 2014 for the $13 million balance relating to Plant Branch Units 1 and 2 in its order for the 2011 IRP and Georgia Power has requested similar treatment for the balances related to Plant Branch Units 3 and 4 and Plant Yates Units 6 and 7 in the 2013 IRP. Georgia Power has also requested that the Georgia PSC approve the deferral of the costs associated with material and supplies remaining at the unit retirement dates to a regulatory asset, to be amortized over a time period deemed appropriate by the Georgia PSC. As a result of this regulatory treatment, the decertification of these units is not expected to have a material impact on Southern Company's financial statements. The Georgia PSC is scheduled to vote on the 2013 IRP by July 2013.

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, 2012, the balance in the regulatory asset related to storm damage was $38 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.

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Fuel Cost Recovery

The traditional operating companies each have established fuel cost recovery rates approved by their respective state PSCs. The traditional operating companies have experienced lower pricing for natural gas resulting in an increase in natural gas generation and a decrease in coal generation, which is currently more costly. The lower cost of natural gas has 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. At December 31, 2011, total under recovered fuel costs in the balance sheets of Alabama Power and Georgia Power were approximately $169 million, and total over recovered fuel costs in the balance sheets of Gulf Power and Mississippi Power were approximately $52 million. 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 annual cash flow. The traditional operating companies continuously monitor the under or over recovered fuel cost balances.

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

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 to be placed in service in 2013), which will have a positive impact on the future cash flows of Southern Company through 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 to be 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 will have a positive impact on the future cash flows of Southern Company through 2014.

Due to the significant amount of estimated bonus depreciation for 2013, a portion of Southern Company's tax credit utilization will be deferred. Consequently, Southern Company's positive cash flow benefit is estimated to be between $275 million and $310 million in 2013.

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, including the ongoing construction of solar units at Southern Power, Plant Vogtle Units 3 and 4 at Georgia Power, and the Kemper IGCC at Mississippi Power, 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 $5.5 billion, $5.8 billion, and $5.2 billion for 2013, 2014, and 2015, respectively.

The two largest construction projects currently underway in the Southern Company system are Plant Vogtle Units 3 and 4 (45.7% ownership interest in two units, each with approximately 1,100 MWs) and the construction of the Kemper IGCC (for a total of 582 MWs). See Note 3 to the financial statements under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" and "Integrated Coal Gasification Combined Cycle" for additional information. See RISK FACTORS of Southern Company in Item 1A of the Form 10-K for a discussion of 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.

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Investments in 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. Southern Company reviews all important lease assumptions at least annually, or more frequently if events or changes in circumstances indicate that a change in assumptions has occurred or may occur. These assumptions include the effective tax rate, the residual value, the credit quality of the lessees, and the timing of expected tax cash flows. See Note 1 to the financial statements under "Leveraged Leases" for additional information.

The recent financial and operational performance of one of Southern Company's lessees and the associated generation assets has raised potential concerns on the part of Southern Company as to the credit quality of the lessee and the residual value of the assets. Due to the poor performance of the generation assets and the uncertainties surrounding the receipt of future rent payments and its ability to successfully restructure the project, Southern Company placed the lease on nonaccrual status whereby, effective July 2012, income associated with this investment is not recognized in the financial statements. The lessee was unable to pay its December 2012 semiannual rent payment in full. To avoid a default on the lease and the project's nonrecourse debt, the due date for the December 2012 rent payment and the associated debt payment was extended to March 6, 2013 while restructuring negotiations continued between the parties to the transaction. The aim of the negotiations is to restructure the debt payments and the related rental payments to allow additional capital investment in the project to be made by Southern Company to improve the operation of the generation assets. Such operational improvements are projected to provide sufficient cash flows for Southern Company to realize the full amount of its investment in the lease receivable. The parties to the lease have reached general agreement as to the restructuring and Southern Company believes that it is likely that it will be able to complete the restructuring prior to the end of the first quarter 2013. If the restructuring is successfully completed, Southern Company will be required to record a reduction in leveraged lease income of up to approximately $17 million at that time. However, if the restructuring is unsuccessful and the project is ultimately abandoned, the potential impairment loss that would be incurred is approximately $90 million on an after-tax basis. The ultimate outcome of this matter cannot be determined at this time.

Other Matters

Southern Company and its subsidiaries are involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, Southern Company and its subsidiaries are subject to certain claims and legal actions arising in the ordinary course of business. The business activities of Southern Company's subsidiaries are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements, such as air quality and water standards, has 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 byproducts, 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 March 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. On March 12, 2012, the NRC issued three orders and a request for information based on the July 2011 NRC task force report recommendations that included, among other items, additional mitigation strategies for beyond-design-basis events, enhanced spent fuel pool instrumentation capabilities, hardened vents for certain classes of containment structures, including the one in use at Plant Hatch, site specific evaluations for seismic and flooding hazards, and various plant evaluations to ensure adequate coping capabilities during station blackout and other conditions. On August 29, 2012, the NRC staff issued the final interim staff guidance document, which offers acceptable approaches to meeting the requirements of the NRC's orders before the December 31, 2016 compliance deadline. The interim staff guidance is not mandatory, but licensees would be required to obtain NRC approval for taking an approach other than as outlined in the interim staff guidance. 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

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does not currently anticipate that the associated compliance costs would have a material impact on Southern Company's financial statements.

See RISK FACTORS of Southern Company in Item 1A of the Form 10-K for a discussion of 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.

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.

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 95% of Southern Company's total operating revenues for 2012, 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, nuclear decommissioning, 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 and its subsidiaries are subject to a number of federal and state laws and regulations, as well as other factors and conditions that subject them to environmental, litigation, income tax, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. Southern Company periodically evaluates its exposure to such risks and, in accordance with GAAP, records reserves for those matters where a non-tax-related loss is considered probable and reasonably estimable and records a tax asset or liability if it is more likely than not that a tax position will be sustained. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect Southern Company's 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

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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 developed from the weighted average of market-observed yields for high quality fixed income securities with maturities that correspond to expected benefit payments.

The following table illustrates the sensitivity to changes in Southern Company's long-term assumptions with respect to the 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 2013	Increase/(Decrease) in Projected Obligation for Pension Plan at December 31, 2012	Increase/(Decrease) in Projected Obligation for Other Postretirement Benefit Plans at December 31, 2012
		(in millions)	
25 basis point change in discount rate	$32/$(30)	$346/$(327)	$72/$(68)
25 basis point change in salaries	$17/$(16)	$93/$(89)	$-/$-
25 basis point change in long-term return on plan assets	$21/$(21)	N/A	N/A

N/A – Not applicable

FINANCIAL CONDITION AND LIQUIDITY

Overview

Southern Company's financial condition remained stable at December 31, 2012. Southern 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 Southern Company system's cash needs. For the three-year period from 2013 through 2015, Southern 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, 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, 2012 as compared to December 31, 2011. In December 2012, certain of the traditional operating companies and other subsidiaries contributed $445 million to the qualified pension plan.

Net cash provided from operating activities in 2012 totaled $4.9 billion, a decrease of $1.0 billion from the corresponding period in 2011. Significant changes in operating cash flow for 2012 as compared to the corresponding period in 2011 include an increase in fossil fuel stock and contributions to the qualified pension plan. Net cash provided from operating activities in 2011 totaled $5.9 billion, an increase of $1.9 billion from the corresponding period in 2010. Significant changes in operating cash flow for 2011 as compared to the corresponding period in 2010 include an increase in net income, a contribution to the qualified pension plan in 2010, and a decrease in taxes paid due to bonus depreciation.

Net cash used for investing activities in 2012, 2011, and 2010 totaled $5.2 billion, $4.2 billion, and $4.3 billion, respectively. The cash used for investing activities for each of these years was primarily for property additions to utility plant.

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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. Net cash used for financing activities totaled $852 million in 2011 due to a reduction of short-term debt outstanding and redemptions of long-term debt. Net cash provided from financing activities totaled $22 million in 2010 primarily due to long-term debt issuances offset mostly by long-term debt redemptions. 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 2012 include an increase of $3.4 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 cash of $687 million primarily due to a decrease in temporary cash investments, an increase in deferred income taxes of $1.1 billion due to bonus depreciation, and $719 million of additional equity.

At the end of 2012, the closing price of Southern Company's common stock was $42.81 per share, compared with a book value of $21.09 per share. The market-to-book value ratio was 203% at the end of 2012, compared with 228% at year-end 2011.

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 2013, as well as in subsequent years, will be contingent on Southern Company's investment opportunities.

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.

In 2010, Georgia Power reached an agreement with the U.S. Department of Energy (DOE) to accept terms for a conditional commitment for federal loan guarantees that would apply to future Georgia Power borrowings related to the construction of Plant Vogtle Units 3 and 4. Any borrowings guaranteed by the DOE would be full recourse to Georgia Power and secured by a first priority lien on Georgia Power's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4. Total guaranteed borrowings would not exceed the lesser of 70% of eligible project costs, or approximately $3.46 billion, and are expected to be funded by the Federal Financing Bank. Final approval and issuance of loan guarantees by the DOE are subject to negotiation of definitive agreements, completion of due diligence by the DOE, receipt of any necessary regulatory approvals, and satisfaction of other conditions. In the event that the DOE does not issue a loan guarantee or Georgia Power determines that the final terms and conditions of the loan guarantee by the DOE are not in the best interest of its customers, Georgia Power expects to finance the construction of Plant Vogtle Units 3 and 4 through traditional capital markets financings. There can be no assurance that the DOE will issue loan guarantees for Georgia Power. The conditional commitment will expire on June 30, 2013, unless further extended by the DOE. See Note 3 to the financial statements under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" for more information on Plant Vogtle Units 3 and 4.

In addition, Mississippi Power received DOE Clean Coal Power Initiative Round 2 (CCPI2) grant funds of $245 million that were used for the construction of the Kemper IGCC. An additional $25 million in CCPI2 grant funds is expected to be received for the initial operation of the Kemper IGCC. On January 29, 2013, Mississippi Power withdrew its application for federal loan guarantees related to 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 Securities and Exchange Commission (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.

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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, 2012, Southern Company and its subsidiaries had approximately $628 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2012 were as follows:

	Expires[(a)]					Executable Term Loans		Due Within One Year	
Company	2013	2014	2016	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	158	350	800	1,308	1,308	56	—	56	102
Georgia Power	—	250	1,500	1,750	1,740	—	—	—	—
Gulf Power	80	195	—	275	275	45	—	45	35
Mississippi Power	135	165	—	300	300	25	40	65	70
Southern Power	—	—	500	500	500	—	—	—	—
Other	50	—	—	50	50	25	—	25	25
Total	$423	$960	$3,800	$5,183	$5,173	$151	$40	$191	$232

(a) No credit arrangements expire in 2015.

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 that are restricted only to the indebtedness of the individual company. Southern Company and its subsidiaries are currently in compliance with all such covenants.

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, 2012 was approximately $1.8 billion.

The traditional operating companies 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 each of the traditional operating companies.

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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	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		(in millions)		(in millions)
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%	
December 31, 2010:					
Commercial paper	$1,295	0.3%	$690	0.3%	$1,305

(a) Excludes notes payable related to other energy service contracts of $5 million, $6 million, and $2 million at December 31, 2012, 2011, and 2010, respectively.

(b) Average and maximum amounts are based upon daily balances during the twelve-month periods ended December 31, 2012, 2011, and 2010.

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 2012, Southern Company issued 12.1 million shares of common stock for approximately $397 million through the employee and director stock plans. Since mid-2011, Southern Company has issued additional equity only through its employee and director stock plans. 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. Under this program, approximately 9 million shares have been repurchased through December 31, 2012 at a total cost of $430 million. Pursuant to Board approval, Southern Company may repurchase shares through open market purchases or privately negotiated transactions, in accordance with applicable securities laws.

In addition, Southern Company is not currently issuing shares of common stock through the Southern Investment Plan or its employee savings plan. All sales under the Southern Investment Plan and the employee savings plan are currently being funded with shares acquired on the open market by the independent plan administrators.

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The following table outlines the long-term debt financing activities for Southern Company, the traditional operating companies, and Southern Power for the year ended December 31, 2012:

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	1,000	950	—	1	—	—
Georgia Power	2,300	850	284	284	—	250
Gulf Power	100	91	13	13	—	—
Mississippi Power	600	90	—	—	101	115
Southern Power	—	—	—	—	6	2
Total	$4,000	$2,481	$297	$298	$107	$367

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.

In January 2012, Southern Company's $500 million aggregate principal amount of Series 2007A 5.30% Senior Notes matured.

The table above does not reflect Mississippi Power's receipt on March 6, 2012 of a $150 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. Until the acquisition is closed, the deposit bears interest at Mississippi Power's AFUDC rate adjusted for income taxes, which was 9.967% per annum at December 31, 2012, and is 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.

Mississippi Power's "Other Long-Term Debt Issuances" reflected in the table above include $51 million related to an agreement entered into by the Mississippi Business Finance Corporation in August 2012 for the issuance of up to $85 million of taxable revenue bonds for the benefit of Mississippi Power. During 2012, the Mississippi Business Finance Corporation issued $51 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 of up to $34 million under the agreement will be used for the same purposes.

In addition, Mississippi Power's "Other Long-Term Debt Issuances" reflected in the table above includes a term loan borrowing of $50 million. In November 2012, Mississippi Power entered into a one-year $100 million aggregate principal amount floating rate term loan agreement that bears interest based on one-month London Interbank Offered Rate. The first advance in the amount of $50 million was made in November 2012. Subsequent to December 31, 2012, the second advance in the amount of $50 million was made. The proceeds of this loan were used solely for working capital and other general corporate purposes, including Mississippi Power's continuous construction program.

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.

Purchase of the Plant Daniel Combined Cycle Generating Units

In 2001, Mississippi Power began the initial 10-year term of an operating lease agreement for Plant Daniel Units 3 and 4.

In October 2011, Mississippi Power purchased Plant Daniel Units 3 and 4 for approximately $85 million in cash and the assumption of $270 million face value 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. Accounting rules require that Plant Daniel Units 3 and 4 be reflected on Southern Company's financial statements at the time of the purchase at the fair value of the consideration rendered. Based on interest rates as of October 20, 2011, the fair value of the debt assumed was approximately $346 million. Accordingly, Plant Daniel Units 3 and 4 were reflected in Southern Company's financial statements at approximately $431 million.

In connection with the purchase of Plant Daniel Units 3 and 4, Mississippi Power filed a request in July 2011 for an accounting order from the Mississippi PSC. This order, as approved on January 11, 2012, authorized Mississippi Power to defer as a regulatory asset, for the 10-year period ending October 2021, the difference between the revenue requirement under the purchase option for Plant Daniel Units 3 and 4 (assuming a remaining 30-year life) and the revenue requirement assuming the continuation of the operating lease regulatory treatment with the accumulated deferred balance at the end of the deferral being amortized into rates over the remaining life of Plant Daniel Units 3 and 4. In November 2011, Mississippi Power filed a request with the FERC seeking the same accounting and regulatory treatment for its wholesale cost-based jurisdiction. The ultimate outcome of this matter cannot be determined at this time.

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.

The maximum potential collateral requirements under these contracts at December 31, 2012 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements (in millions)
At BBB and Baa2	$9
At BBB- and/or Baa3	645
Below BBB- and/or Baa3	2,574

On March 6, 2012, Mississippi Power received a $150 million interest-bearing refundable deposit from SMEPA to be applied to the sale price for the pending sale of an undivided interest in the Kemper IGCC. Until the acquisition is closed, the deposit bears interest at Mississippi Power's AFUDC rate adjusted for income taxes, which was 9.967% per annum at December 31, 2012, and is 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.

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.

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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, 2012 have a notional amount of $350 million and are related to fixed and floating rate obligations over the next several years. The weighted average interest rate on $3.2 billion of long-term and short-term variable interest rate exposure that has not been hedged at January 1, 2013 was 0.73%. 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 $32 million at January 1, 2013. 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 sales 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, 2012 when compared to the December 31, 2011 reporting period.

The changes in fair value of energy-related derivative contracts, the majority of which are composed of regulatory hedges, for the years ended December 31 were as follows:

	2012 Changes	2011 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	$(231)	$(196)
Contracts realized or settled	206	179
Current period changes[(a)]	(60)	(214)
Contracts outstanding at the end of the period, assets (liabilities), net	$(85)	$(231)

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

The changes in the fair value positions of the energy-related derivative contracts, which are substantially all attributable to both the volume and the price of natural gas, for the years ended December 31 were as follows:

	2012	2011

	Changes	Changes
	Fair Value	
	(in millions)	
Natural gas swaps	$128	$(20)
Natural gas options	19	(15)
Other energy-related derivatives	(1)	—
Total changes	$146	$(35)

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

	2012	2011
	mmBtu* Volume (in millions)	
Commodity – Natural gas swaps	171	123
Commodity – Natural gas options	105	66
Total hedge volume	276	189

*million British thermal units (mmBtu)

The weighted average swap contract cost above market prices was approximately $0.39 per mmBtu as of December 31, 2012 and $1.51 per mmBtu as of December 31, 2011. 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, the net fair value of energy-related derivative contracts by hedge designation was reflected in the financial statements as follows:

Asset (Liability) Derivatives	2012	2011
	(in millions)	
Regulatory hedges	$(86)	$(221)
Cash flow hedges	—	(1)
Not designated	1	(9)
Total fair value	$(85)	$(231)

Energy-related derivative contracts which are designated as regulatory hedges relate 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 they are recovered through the fuel cost recovery clauses. Gains and losses on energy-related derivatives that are designated as cash flow hedges are mainly used by Southern Power to hedge anticipated purchases and sales and 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.
Total net unrealized pre-tax gains (losses) recognized in the statements of income for the years ended December 31, 2012, 2011, and 2010 for energy-related derivative contracts that are not hedges were $9 million, $(6) million, and $(2) million, respectively.
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, 2012 were as follows:

	Fair Value Measurements December 31, 2012			
	Total Fair Value	Maturity Year 1	Years 2&3	Years 4&5
	(in millions)			
Level 1	$—	$—	$—	$—
Level 2	(85)	(64)	(23)	2
Level 3	—	—	—	—

Fair value of contracts outstanding at end of period	$(85)	$(64)	$(23)	$2

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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. See FUTURE EARNINGS POTENTIAL – "Investments in Leveraged Leases" herein for additional information.

Capital Requirements and Contractual Obligations

The Southern Company system's construction program is currently estimated to be $5.5 billion for 2013, $5.8 billion for 2014, and $5.2 billion for 2015. Included in this amount are expenditures related to the construction of the Kemper IGCC of $513 million and $218 million in 2013 and 2014, respectively, which are net of SMEPA's 15% proposed ownership share of the Kemper IGCC of approximately $492 million and $28 million in 2013 and 2014, respectively. The estimated share for SMEPA in 2013 reflects estimated construction costs relating to SMEPA's proposed ownership interest to be incurred through December 31, 2013 (including construction costs for all prior years relating to its proposed ownership interest). Capital expenditures to comply with existing environmental statutes and regulations included in these estimated amounts are $1.0 billion, $1.5 billion, and $1.1 billion for 2013, 2014, and 2015, respectively. These amounts include capital expenditures related to contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements, as well as capital expenditures and compliance costs associated with the MATS rule.

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.

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.

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Contractual Obligations

	2013	2014-2015	2016-2017 (in millions)	After 2017	Uncertain Timing[d]	Total
Long-term debt[a] —						
Principal	$2,312	$2,866	$2,495	$13,804	$—	$21,477
Interest	821	1,491	1,318	10,214	—	13,844
Preferred and preference stock dividends[b]	65	130	130	—	—	325
Financial derivative obligations[c]	75	35	1	—	—	111
Operating leases	113	148	77	84	—	422
Capital leases	23	21	15	21	—	80
Unrecognized tax benefits[d]	5	—	—	—	65	70
Purchase commitments —						
Capital[e]	4,987	10,013	—	—	—	15,000
Fuel[f]	4,518	6,070	2,638	3,280	—	16,506
Purchased power[g]	246	617	650	2,903	—	4,416
Other[h]	184	516	271	1,034	—	2,005
Trusts —						
Nuclear decommissioning[i]	2	4	4	31	—	41
Pension and other postretirement benefit plans[j]	102	201	—	—	—	303
Total	$13,453	$22,112	$7,599	$31,371	$65	$74,600

(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, 2013, 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) The timing related to the realization of $65 million in unrecognized tax benefits in individual years beyond 12 months cannot be reasonably and reliably estimated due to uncertainties in the timing of the effective settlement of tax positions. See Note 5 to the financial statements under "Unrecognized Tax Benefits" for additional information.

(e) The Southern Company system provides estimated capital expenditures for a three-year period, including capital expenditures and compliance costs associated with existing environmental regulations, including the MATS rule. 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, 2012, 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) 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, 2012.

(g) Estimated minimum long-term obligations for various long-term commitments for the purchase of capacity and energy. Amounts include 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) Projections of nuclear decommissioning trust fund contributions are based on the 2010 ARP for Georgia Power.

(j) 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.

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Cautionary Statement Regarding Forward-Looking Statements

Southern Company's 2012 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, dividend payout ratios, projections for the qualified pension plan, postretirement benefit plan, and nuclear decommissioning trust fund contributions, financing activities, start and completion dates of construction projects, plans and estimated costs for new generation resources, filings with state and federal regulatory authorities, impact of the Tax Relief Act, 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 byproducts, and emissions of sulfur, nitrogen, carbon, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, financial reform legislation, 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, 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, including the development and construction of facilities with designs that have not been finalized or previously constructed, 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 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;
- regulatory approvals and actions related to Plant Vogtle Units 3 and 4, including Georgia PSC approvals, NRC actions, and potential DOE loan guarantees;
- regulatory approvals and legislative actions related to the Kemper IGCC, including Mississippi PSC approvals and legislation relating to cost recovery for the Kemper IGCC, the SMEPA purchase decision, satisfaction of requirements to utilize investment tax credits and grants, and the outcome of any proceedings regarding the Mississippi PSC's issuance of the certificate of public convenience and necessity for the Kemper IGCC;

- 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 availability or benefits of proposed 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.

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CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2012, 2011, and 2010
Southern Company and Subsidiary Companies 2012 Annual Report

	2012	2011	2010
		(in millions)	
Operating Revenues:			
Retail revenues	$14,187	$15,071	$14,791
Wholesale revenues	1,675	1,905	1,994
Other electric revenues	616	611	589
Other revenues	59	70	82
Total operating revenues	16,537	17,657	17,456
Operating Expenses:			
Fuel	5,057	6,262	6,699
Purchased power	544	608	563
Other operations and maintenance	3,791	3,938	4,010
MC Asset Recovery insurance settlement	(19)	—	—
Depreciation and amortization	1,787	1,717	1,513
Taxes other than income taxes	914	901	869
Total operating expenses	12,074	13,426	13,654
Operating Income	4,463	4,231	3,802
Other Income and (Expense):			
Allowance for equity funds used during construction	143	153	194
Interest income	40	21	24
Interest expense, net of amounts capitalized	(859)	(857)	(895)
Other income (expense), net	(38)	(61)	(59)
Total other income and (expense)	(714)	(744)	(736)
Earnings Before Income Taxes	3,749	3,487	3,066
Income taxes	1,334	1,219	1,026
Consolidated Net Income	2,415	2,268	2,040
Dividends on Preferred and Preference Stock of Subsidiaries	65	65	65
Consolidated Net Income After Dividends on Preferred and Preference Stock of Subsidiaries	$2,350	$2,203	$1,975
Common Stock Data:			
Earnings per share (EPS)—			
Basic EPS	$2.70	$2.57	$2.37
Diluted EPS	2.67	2.55	2.36
Average number of shares of common stock outstanding — (in millions)			
Basic	871	857	832
Diluted	879	864	837
Cash dividends paid per share of common stock	$1.9425	$1.8725	$1.8025

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

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2012, 2011, and 2010
Southern Company and Subsidiary Companies 2012 Annual Report

	2012	2011	2010
		(in millions)	
Consolidated Net Income	$2,415	$2,268	$2,040
Other comprehensive income:			
Qualifying hedges:			
Changes in fair value, net of tax of $(7), $(10), and $-, respectively	(12)	(18)	(1)
Reclassification adjustment for amounts included in net income, net of tax of $7, $6, and $9, respectively	11	9	15
Marketable securities:			
Change in fair value, net of tax of $-, $(2), and $(2), respectively	—	(4)	(3)
Pension and other postretirement benefit plans:			
Benefit plan net gain (loss), net of tax of $(2), $(1), and $1, respectively	(3)	(2)	6
Reclassification adjustment for amounts included in net income, net of tax of $(4), $(14), and $1, respectively	(8)	(26)	1
Total other comprehensive income (loss)	(12)	(41)	18
Dividends on preferred and preference stock of subsidiaries	(65)	(65)	(65)
Consolidated Comprehensive Income	$2,338	$2,162	$1,993

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

CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2012, 2011, and 2010
Southern Company and Subsidiary Companies 2012 Annual Report

	2012	2011 (in millions)	2010
Operating Activities:			
Consolidated net income	$2,415	$2,268	$2,040
Adjustments to reconcile consolidated net income to net cash provided from operating activities —			
Depreciation and amortization, total	2,145	2,048	1,831
Deferred income taxes	1,096	1,155	1,038
Allowance for equity funds used during construction	(143)	(153)	(194)
Pension, postretirement, and other employee benefits	(398)	(45)	(614)
Stock based compensation expense	55	42	33
Generation construction screening costs	—	—	(51)
Retail fuel cost-recovery - long-term	123	—	—
Other, net	56	15	(33)
Changes in certain current assets and liabilities —			
-Receivables	234	362	80
-Fossil fuel stock	(452)	(62)	135
-Materials and supplies	(97)	(60)	(30)
-Other current assets	(37)	(17)	(17)
-Accounts payable	(89)	(5)	4
-Accrued taxes	(71)	330	(308)
-Accrued compensation	(28)	10	180
-Retail fuel cost over recovery - short-term	129	(3)	(178)
-Other current liabilities	(40)	18	75
Net cash provided from operating activities	4,898	5,903	3,991
Investing Activities:			
Property additions	(4,809)	(4,525)	(4,086)
Investment in restricted cash	(280)	1	(50)
Distribution of restricted cash	284	63	25
Nuclear decommissioning trust fund purchases	(1,046)	(2,195)	(2,009)
Nuclear decommissioning trust fund sales	1,043	2,190	2,004
Cost of removal, net of salvage	(149)	(93)	(125)
Change in construction payables, net	(84)	198	29
Other investing activities	(127)	178	(44)
Net cash used for investing activities	(5,168)	(4,183)	(4,256)
Financing Activities:			
Increase (decrease) in notes payable, net	(30)	(438)	659
Proceeds —			
Long-term debt issuances	4,404	3,719	3,151
Interest-bearing refundable deposit related to asset sale	150	—	—
Common stock issuances	397	723	772
Redemptions and repurchases —			
Long-term debt	(3,169)	(3,170)	(2,966)
Common stock repurchased	(430)	—	—

Payment of common stock dividends	(1,693)	(1,601)	(1,496)
Payment of dividends on preferred and preference stock of subsidiaries	(65)	(65)	(65)
Other financing activities	19	(20)	(33)
Net cash provided from (used for) financing activities	(417)	(852)	22
Net Change in Cash and Cash Equivalents	(687)	868	(243)
Cash and Cash Equivalents at Beginning of Year	1,315	447	690
Cash and Cash Equivalents at End of Year	$628	$1,315	$447

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

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CONSOLIDATED BALANCE SHEETS
At December 31, 2012 and 2011
Southern Company and Subsidiary Companies 2012 Annual Report

Assets	2012	2011
		(in millions)
Current Assets:		
Cash and cash equivalents	$628	$1,315
Restricted cash and cash equivalents	7	8
Receivables —		
Customer accounts receivable	961	1,074
Unbilled revenues	441	376
Under recovered regulatory clause revenues	29	143
Other accounts and notes receivable	235	282
Accumulated provision for uncollectible accounts	(17)	(26)
Fossil fuel stock, at average cost	1,819	1,367
Materials and supplies, at average cost	1,000	903
Vacation pay	165	160
Prepaid expenses	657	385
Other regulatory assets, current	163	239
Other current assets	74	46
Total current assets	6,162	6,272
Property, Plant, and Equipment:		
In service	63,251	59,744
Less accumulated depreciation	21,964	21,154
Plant in service, net of depreciation	41,287	38,590
Other utility plant, net	263	55
Nuclear fuel, at amortized cost	851	774
Construction work in progress	5,989	5,591
Total property, plant, and equipment	48,390	45,010
Other Property and Investments:		
Nuclear decommissioning trusts, at fair value	1,303	1,207
Leveraged leases	670	649
Miscellaneous property and investments	216	262
Total other property and investments	2,189	2,118
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	1,385	1,365
Unamortized debt issuance expense	133	156
Unamortized loss on reacquired debt	309	285
Other regulatory assets, deferred	4,032	3,579
Other deferred charges and assets	549	482
Total deferred charges and other assets	6,408	5,867
Total Assets	$63,149	$59,267

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

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CONSOLIDATED BALANCE SHEETS
At December 31, 2012 and 2011
Southern Company and Subsidiary Companies 2012 Annual Report

Liabilities and Stockholders' Equity	2012	2011
		(in millions)
Current Liabilities:		
Securities due within one year	$2,335	$1,717
Interest-bearing refundable deposit related to asset sale	150	—
Notes payable	825	859
Accounts payable	1,387	1,553
Customer deposits	370	347
Accrued taxes —		
Accrued income taxes	7	13
Unrecognized tax benefits	2	22
Other accrued taxes	391	425
Accrued interest	237	226
Accrued vacation pay	212	205
Accrued compensation	433	450
Liabilities from risk management activities	75	209
Other regulatory liabilities, current	107	125
Other current liabilities	483	426
Total current liabilities	7,014	6,577
Long-Term Debt (See accompanying statements)	19,274	18,647
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	9,938	8,809
Deferred credits related to income taxes	211	224
Accumulated deferred investment tax credits	894	611
Employee benefit obligations	2,540	2,442
Asset retirement obligations	1,748	1,321
Other cost of removal obligations	1,194	1,165
Other regulatory liabilities, deferred	289	297
Other deferred credits and liabilities	668	514
Total deferred credits and other liabilities	17,482	15,383
Total Liabilities	43,770	40,607
Redeemable Preferred Stock of Subsidiaries (See accompanying statements)	375	375
Total Stockholders' Equity (See accompanying statements)	19,004	18,285
Total Liabilities and Stockholders' Equity	$63,149	$59,267
Commitments and Contingent Matters (See notes)		

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

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CONSOLIDATED STATEMENTS OF CAPITALIZATION
At December 31, 2012 and 2011
Southern Company and Subsidiary Companies 2012 Annual Report

		2012	2011	2012	2011
		(in millions)		(percent of total)	
Long-Term Debt:					
Long-term debt payable to affiliated trusts —					
Maturity	Interest Rates				
Variable rate (3.41% at 1/1/13) due 2042		$206	$206		
Total long-term debt payable to affiliated trusts		206	206		
Long-term senior notes and debt —					
Maturity	Interest Rates				
2012	4.85% to 5.30%	—	1,203		
2013	1.30% to 6.00%	1,436	1,436		
2014	4.15% to 4.90%	434	437		
2015	0.55% to 5.25%	2,375	1,175		
2016	1.95% to 5.30%	1,360	1,210		
2017	5.50% to 5.90%	1,095	1,095		
2018 through 2051	2.25% to 8.20%	10,073	8,702		
Variable rates (0.60% to 0.95% at 1/1/12) due 2012		—	490		
Variable rates (0.58% to 1.21% at 1/1/13) due 2013		876	650		
Total long-term senior notes and debt		17,649	16,398		
Other long-term debt —					
Pollution control revenue bonds —					
Maturity	Interest Rates				
2019 through 2049	0.55% to 6.00%	1,593	1,590		
Variable rate (0.13% at 1/1/13) due 2015		54	54		
Variable rate (0.17% at 1/1/13) due 2016		4	4		
Variable rate (0.13% to 0.17% at 1/1/13) due 2017		36	36		
Variable rates (0.08% to 0.24% at 1/1/13) due 2018 to 2052		1,664	1,667		
Plant Daniel revenue bonds (7.13%) due 2021		270	270		
Total other long-term debt		3,621	3,621		
Capitalized lease obligations		80	93		
Unamortized debt premium (related to plant acquisition)		88	78		
Unamortized debt discount		(35)	(32)		
Total long-term debt (annual interest requirement — $821 million)		21,609	20,364		
Less amount due within one year		2,335	1,717		
Long-term debt excluding amount due within one year		19,274	18,647	49.9%	50.0%

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CONSOLIDATED STATEMENTS OF CAPITALIZATION
(continued)
At December 31, 2012 and 2011
Southern Company and Subsidiary Companies 2012 Annual Report

	2012	2011	2012	2011
	(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	1.0	1.0
Common Stockholders' Equity:				
Common stock, par value $5 per share —	4,389	4,328		
Authorized — 1.5 billion shares				
Issued — 2012: 878 million shares				
— 2011: 866 million shares				
Treasury — 2012: 10.0 million shares				
— 2011: 0.5 million shares				
Paid-in capital	4,855	4,410		
Treasury, at cost	(450)	(17)		
Retained earnings	9,626	8,968		
Accumulated other comprehensive income (loss)	(123)	(111)		
Total common stockholders' equity	18,297	17,578	47.3	47.1
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 — 5.63% to 6.50%	343	343		
— 14 million shares (non-cumulative)				
— $100 par or stated value — 6.00% to 6.50%	319	319		
— 3 million shares (non-cumulative)				
Total preferred and preference stock of subsidiaries (annual dividend requirement — $45 million)	707	707	1.8	1.9
Total stockholders' equity	19,004	18,285		
Total Capitalization	$38,653	$37,307	100.0 %	100.0 %

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

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CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
For the Years Ended December 31, 2012, 2011, and 2010
Southern Company and Subsidiary Companies 2012 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, 2009	820,152	(505)	$4,101	$2,995	$(15)	$7,885	$(88)	$707	$15,585
Net income after dividends on preferred and preference stock of subsidiaries	—	—	—	—	—	1,975	—	—	1,975
Other comprehensive income (loss)	—	—	—	—	—	—	18	—	18
Stock issued	23,662	—	118	654	—	—	—	—	772
Stock-based compensation	—	—	—	52	—	—	—	—	52
Cash dividends	—	—	—	—	—	(1,496)	—	—	(1,496)
Other	—	31	—	1	—	2	—	—	3
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

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

NOTES TO FINANCIAL STATEMENTS
Southern Company and Subsidiary Companies 2012 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.

NOTES (continued)
Southern Company and Subsidiary Companies 2012 Annual Report

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

	2012	2011	Note
	(in millions)		
Deferred income tax charges	$1,318	$1,293	(a)
Deferred income tax charges — Medicare subsidy	72	77	(j)
Asset retirement obligations-asset	141	117	(a,h)
Asset retirement obligations-liability	(71)	(42)	(a,h)
Other cost of removal obligations	(1,225)	(1,196)	(a)
Deferred income tax credits	(212)	(225)	(a)
State income tax credits	(36)	(62)	(k)
Loss on reacquired debt	309	285	(b)
Vacation pay	165	160	(c,h)
Under recovered regulatory clause revenues	38	50	(d)
Over recovered regulatory clause revenues	(18)	(28)	(d)
Building leases	40	43	(f)
Generating plant outage costs	30	38	(l)
Under recovered storm damage costs	38	43	(d)
Property damage reserves	(193)	(206)	(g)
Cancelled construction projects	65	12	(m)
Power purchase agreement charges	138	95	(h,n)
Fuel hedging-asset	118	249	(d)
Fuel hedging-liability	(24)	(13)	(d)
Other regulatory assets	204	183	(d)
Environmental remediation-asset	74	71	(g,h)
Environmental remediation-liability	(8)	(8)	(g)
Other regulatory liabilities	(14)	(30)	(d,i)
Retiree benefit plans	3,373	2,959	(e,h)
Total regulatory assets (liabilities), net	$4,322	$3,865	

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 65 years. Asset retirement and removal assets and liabilities will be settled and trued up following completion of the related activities. At December 31, 2012, other cost of removal obligations included $31 million that will be amortized during 2013 in accordance with an Alternate Rate Plan for Georgia Power for the years 2011 through 2013 (2010 ARP). See Note 3 under "Retail Regulatory Matters – Georgia Power – Rate Plans" for additional information.

(b) Recovered over either the remaining life of the original issue or, if refinanced, over the life of the new issue, which may range up to 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) Recovered over the remaining lives of the buildings through 2026.

(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) Additional tax benefits resulting from the Georgia state income tax credit settlement that are being amortized over a 21-month period that began in April 2012, in accordance with a Georgia PSC order.

(l) Recovered over the respective operating cycles, which range from 18 months to 10 years. See "Property, Plant, and Equipment" herein for additional information.

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(m) Costs associated with construction of environmental controls that will not be completed as a result of unit retirements and deferred in accordance with the 2010 ARP. Amortization is expected to begin January 1, 2014, subject to approval by the Georgia PSC.
(n) Recovered over the life of the power purchase agreement (PPA) for periods up to 14 years.

In the event that a portion of a traditional operating company's operations is no longer subject to applicable accounting rules for rate regulation, such company would be required to write off to income or reclassify to accumulated 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 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 $23 million in 2012, $19 million in 2011, and $23 million in 2010. At December 31, 2012, 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.

Under the American Recovery and Reinvestment Act of 2009, certain projects at certain Southern Company subsidiaries are eligible for ITCs or cash grants. These subsidiaries have 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 $2.6 million and $0.9 million in 2012 and 2011, respectively. Furthermore, the tax basis of the asset is reduced by 50% of the credits received, resulting in a deferred tax asset. The subsidiaries have 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. These basis differences will reverse and be recorded to income tax expense over the useful life of the asset once placed in service.

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.

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

	2012	2011
	(in millions)	
Generation	$33,444	$31,751
Transmission	8,747	8,240
Distribution	15,958	15,458
General	4,208	3,413
Plant acquisition adjustment	124	124
Utility plant in service	62,481	58,986
Information technology equipment and software	230	220
Communications equipment	430	428
Other	110	110
Other plant in service	770	758
Total plant in service	$63,251	$59,744

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 expense 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 also defers the costs of certain significant inspection costs for the combustion turbines at Plant McIntosh and amortizes such costs over 10 years, which approximates the expected maintenance cycle.

The amount of non-cash property additions recognized for the years ended December 31, 2012, 2011, and 2010 was $524 million, $929 million, and $427 million, respectively. These amounts are comprised of construction related accounts payable outstanding at each year end together with retention amounts accrued during the respective year. Included in the non-cash property additions for the year ended December 31, 2011 was $346 million for the fair value of the debt assumed for Mississippi Power's purchase of the combined cycle generating units 3 and 4 built at Plant Daniel (Plant Daniel Units 3 and 4). In October 2011, Mississippi Power purchased Plant Daniel Units 3 and 4 for approximately $85 million in cash and the assumption of $270 million face value 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. Accounting rules require that Plant Daniel Units 3 and 4 be reflected on Southern Company's financial statements at the time of the purchase at the fair value of the consideration rendered. Based on interest rates as of October 20, 2011, the fair value of the debt assumed was approximately $346 million. The fair value of the debt was determined using a discounted cash flow model based on Mississippi Power's borrowing rate at the closing date. The fair value is considered a Level 2 disclosure for financial reporting purposes. Accordingly, Plant Daniel Units 3 and 4 are reflected in Southern Company's financial statements at approximately $431 million.

Southern Power acquires generation assets as part of its overall growth strategy. Southern Power accounts for business acquisitions from non-affiliates as business combinations utilizing the acquisition method in accordance with GAAP. 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.
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 2012, 3.2% in 2011, and 3.3% in 2010. 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 $21.5 billion and $20.7 billion at December 31, 2012 and 2011,

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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 the 2010 ARP, Georgia Power is amortizing approximately $31 million annually of the remaining regulatory liability related to other cost of removal obligations over the three years ending December 31, 2013. 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 $479 million and $456 million at December 31, 2012 and 2011, respectively.

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. 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. See Note 3 under "Retail Regulatory Matters – Georgia Power – Rate Plans" for additional information related to Georgia Power's cost of removal 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, underground storage tanks, asbestos removal, and disposal of polychlorinated biphenyls in certain transformers. The Southern Company system also has identified retirement obligations related to certain transmission and distribution facilities, co-generation facilities, certain wireless communication towers, and certain structures authorized by the U.S. Army Corps of Engineers. However, liabilities for the removal of these assets have not been recorded because the range of time over which the applicable company may settle these obligations is unknown and cannot be reasonably estimated. 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:

	2012	2011
	(in millions)	
Balance at beginning of year	$1,344	$1,266
Liabilities incurred	45	1
Liabilities settled	(16)	(13)
Accretion	112	82
Cash flow revisions	272	8
Balance at end of year	$1,757	$1,344

Nuclear Decommissioning

The 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, 2012 and 2011, approximately $91 million and $39 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 $93 million and $42 million at December 31, 2012 and 2011, 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, 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. At December 31, 2011, investment securities in the Funds totaled $1.2 billion consisting of equity securities of $626 million, debt securities of $543 million, and $36 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, $2.2 billion, and $2.0 billion in 2012, 2011, and 2010, respectively, all of which were reinvested. 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. For 2010, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $139 million, of which $6 million related to securities held in the Funds at December 31, 2010. 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, 2012, the accumulated provisions for decommissioning were as follows:

	Plant Farley	Plant Hatch	Plant Vogtle Units 1 and 2
	(in millions)		
External trust funds	$604	$435	$256
Internal reserves	22	—	—
Total	$626	$435	$256

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Site study cost is the estimate to decommission a specific facility as of the site study year. The estimated costs of decommissioning based on the most current studies, which were performed in 2008 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	2065	2068	2072
	(in millions)		
Site study costs:			
Radiated structures	$1,060	$680	$568
Non-radiated structures	72	51	76
Total site study costs	$1,132	$731	$644

The decommissioning periods and site study costs for Plant Vogtle Units 1 and 2 reflect the extended operating license approved by the NRC in 2009. 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, 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 2009. Effective for the years 2011 through 2013, the annual decommissioning cost for ratemaking is $2 million for Plant Hatch. 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 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 8.2%, 9.1%, and 12.5% of net income for 2012, 2011, and 2010, respectively.

Cash payments for interest totaled $803 million, $832 million, and $789 million in 2012, 2011, and 2010, respectively, net of amounts capitalized of $83 million, $78 million, and $86 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.

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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 2012 and $29 million in 2011. Alabama Power, Gulf Power, and Mississippi Power also have the authority based on orders from their state PSCs to accrue certain additional amounts as circumstances warrant. In 2012, there were no such additional accruals. In 2011, such additional accruals totaled $31 million, all at Alabama Power. 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. The recent financial and operational performance of one of Southern Company's lessees and the associated generation assets has raised potential concerns on the part of Southern Company as to the credit quality of the lessee and the residual value of the assets. Due to the poor performance of the generation assets and the uncertainties surrounding the receipt of future rent payments and its ability to successfully restructure the project, Southern Company placed the lease on nonaccrual status whereby, effective July 2012, income associated with this investment is not recognized in the financial statements. The lessee was unable to pay its December 2012 semiannual rent payment in full. To avoid a default on the lease and the project's nonrecourse debt, the due date for the December 2012 rent payment and the associated debt payment was extended to March 6, 2013 while restructuring negotiations continued between the parties to the transaction. The aim of the negotiations is to restructure the debt payments and the related rental payments to allow additional capital investment in the project to be made by Southern Company to improve the operation of the generation assets. Such operational improvements are projected to provide sufficient cash flows for Southern Company to realize the full amount of its investment in the lease receivable. The parties to the lease have reached general agreement as to the restructuring and Southern Company believes that it is likely that it will be able to complete the restructuring prior to the end of the first quarter 2013. If the restructuring is successfully completed, Southern Company will be required to record a reduction in leveraged lease income of up to approximately $17 million at that time. However, if the restructuring is unsuccessful and the project is ultimately abandoned, the potential impairment loss that would be incurred is approximately $90 million on an after-tax basis. The ultimate outcome of this matter cannot be determined at this time.

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

	2012	2011
	(in millions)	
Net rentals receivable	$1,214	$1,216
Unearned income	(544)	(567)
Investment in leveraged leases	670	649
Deferred taxes from leveraged leases	(278)	(277)
Net investment in leveraged leases	$392	$372

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

	2012	2011	2010
	(in millions)		
Pretax leveraged lease income	$21	$25	$18
Income tax expense	(8)	(9)	(8)
Net leveraged lease income	$13	$16	$10

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Cash and Cash Equivalents

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

Materials and Supplies

Generally, materials and supplies include the average cost of transmission, distribution, 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 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, 2012, the amount included in accounts payable in the balance sheets that the Company has recognized for the obligation to return cash collateral arising from derivative instruments was immaterial.

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

Comprehensive Income

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

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

	Qualifying Hedges	Marketable Securities	Pension and Other Postretirement Benefit Plans	Accumulated Other Comprehensive Income (Loss)

	(in millions)			
Balance at December 31, 2011	$(44)	$3	$(70)	$(111)
Current period change	(1)	—	(11)	(12)
Balance at December 31, 2012	$(45)	$3	$(81)	$(123)

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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). In December 2012, certain of the traditional operating companies and other subsidiaries contributed $445 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2013. 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, 2013, other postretirement trust contributions are expected to total approximately $28 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 2009 for the 2010 plan year using discount rates for the pension plans and the other postretirement benefit plans of 5.93% and 5.83%, respectively, and an annual salary increase of 4.18%.

	2012		2011		2010	
Discount rate:						
Pension plans	4.26	%	4.98	%	5.52	%
Other postretirement benefit plans	4.05		4.88		5.40	
Annual salary increase	3.59		3.84		3.84	
Long-term return on plan assets:						
Pension plans	8.20		8.45		8.45	
Other postretirement benefit plans	7.29		7.39		7.40	

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) is the weighted average medical care cost trend rate. The weighted average medical care cost trend rates used in measuring the APBO as of December 31, 2012 were as follows:

	Initial Cost Trend Rate	Ultimate Cost Trend Rate	Year That Ultimate Rate Is Reached
Pre-65	8.00%	5.00%	2020

Post-65 medical	6.00	5.00	2020
Post-65 prescription	6.00	5.00	2020

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An annual increase or decrease in the assumed medical care cost trend rate of 1% would affect the APBO and the service and interest cost components at December 31, 2012 as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$126	$(106)
Service and interest costs	7	(6)

Pension Plans
The total accumulated benefit obligation for the pension plans was $8.5 billion at December 31, 2012 and $7.4 billion at December 31, 2011. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2012 and 2011 were as follows:

	2012	2011
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	$8,079	$7,223
Service cost	198	184
Interest cost	393	389
Benefits paid	(336)	(324)
Actuarial loss	968	607
Balance at end of year	9,302	8,079
Change in plan assets		
Fair value of plan assets at beginning of year	6,800	6,834
Actual return (loss) on plan assets	1,010	256
Employer contributions	479	34
Benefits paid	(336)	(324)
Fair value of plan assets at end of year	7,953	6,800
Accrued liability	$(1,349)	$(1,279)

At December 31, 2012, the projected benefit obligations for the qualified and non-qualified pension plans were $8.7 billion and $582 million, respectively. All pension plan assets are related to the qualified pension plan.
Amounts recognized in the balance sheets at December 31, 2012 and 2011 related to the Company's pension plans consist of the following:

	2012	2011
	(in millions)	
Other regulatory assets, deferred	$3,013	$2,614
Other current liabilities	(37)	(34)
Employee benefit obligations	(1,312)	(1,245)
Accumulated OCI	125	109

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Presented below are the amounts included in accumulated OCI and regulatory assets at December 31, 2012 and 2011 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 2013.

	Prior Service Cost	Net (Gain) Loss
	(in millions)	
Balance at December 31, 2012:		
Accumulated OCI	$7	$118
Regulatory assets	100	2,913
Total	$107	$3,031
Balance at December 31, 2011:		
Accumulated OCI	$7	$102
Regulatory assets	128	2,486
Total	$135	$2,588
Estimated amortization in net periodic pension cost in 2013:		
Accumulated OCI	$1	$8
Regulatory assets	26	192
Total	$27	$200

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, 2012 and 2011 are presented in the following table:

	Accumulated OCI	Regulatory Assets
	(in millions)	
Balance at December 31, 2010	$68	$1,749
Net (gain) loss	43	915
Change in prior service costs	—	1
Reclassification adjustments:		
Amortization of prior service costs	(1)	(31)
Amortization of net gain (loss)	(1)	(20)
Total reclassification adjustments	(2)	(51)
Total change	41	865
Balance at December 31, 2011	$109	$2,614
Net (gain) loss	21	519
Change in prior service costs	—	—
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

NOTES (continued)
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Components of net periodic pension cost were as follows:

	2012	2011	2010
	(in millions)		
Service cost	$198	$184	$172
Interest cost	393	389	391
Expected return on plan assets	(581)	(607)	(552)
Recognized net loss	95	21	10
Net amortization	30	32	33
Net periodic pension cost	$135	$19	$54

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, 2012, estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2013	$376
2014	397
2015	419
2016	440
2017	465
2018 to 2022	2,632

NOTES (continued)
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Other Postretirement Benefits
Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2012 and 2011 were as follows:

	2012	2011
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	$1,787	$1,752
Service cost	21	21
Interest cost	85	92
Benefits paid	(99)	(103)
Actuarial loss	71	29
Plan amendments	—	(12)
Retiree drug subsidy	7	8
Balance at end of year	1,872	1,787
Change in plan assets		
Fair value of plan assets at beginning of year	765	802
Actual return on plan assets	93	4
Employer contributions	55	54
Benefits paid	(92)	(95)
Fair value of plan assets at end of year	821	765
Accrued liability	$(1,051)	$(1,022)

Amounts recognized in the balance sheets at December 31, 2012 and 2011 related to the Company's other postretirement benefit plans consist of the following:

	2012	2011
	(in millions)	
Other regulatory assets, deferred	$360	$345
Other current liabilities	(3)	(4)
Employee benefit obligations	(1,048)	(1,018)
Accumulated OCI	7	6

NOTES (continued)
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Presented below are the amounts included in accumulated OCI and regulatory assets at December 31, 2012 and 2011 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 2013.

	Prior Service Cost	Net (Gain) Loss (in millions)	Transition Obligation
Balance at December 31, 2012:			
Accumulated OCI	$—	$7	$—
Regulatory assets	13	342	5
Total	$13	$349	$5
Balance at December 31, 2011:			
Accumulated OCI	$—	$6	$—
Regulatory assets	17	314	14
Total	$17	$320	$14
Estimated amortization as net periodic postretirement benefit cost in 2013:			
Accumulated OCI	$—	$—	$—
Regulatory assets	4	12	5
Total	$4	$12	$5

The components of OCI, along with the changes in the balance of regulatory assets, related to the other postretirement benefit plans for the plan years ended December 31, 2012 and 2011 are presented in the following table:

	Accumulated OCI (in millions)	Regulatory Assets
Balance at December 31, 2010	$3	$292
Net (gain) loss	3	84
Change in prior service costs/transition obligation	—	(12)
Reclassification adjustments:		
Amortization of transition obligation	—	(10)
Amortization of prior service costs	—	(5)
Amortization of net gain (loss)	—	(4)
Total reclassification adjustments	—	(19)
Total change	3	53
Balance at December 31, 2011	$6	$345
Net (gain) loss	1	35
Change in prior service costs/transition obligation	—	—
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

NOTES (continued)
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Components of the other postretirement benefit plans' net periodic cost were as follows:

	2012	2011	2010
	(in millions)		
Service cost	$21	$21	$25
Interest cost	85	92	100
Expected return on plan assets	(60)	(64)	(63)
Net amortization	20	20	20
Net postretirement cost	$66	$69	$82

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)		
2013	$110	$(11)	$99
2014	116	(12)	104
2015	122	(13)	109
2016	127	(14)	113
2017	130	(16)	114
2018 to 2022	661	(88)	573

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.

NOTES (continued)
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The composition of the Company's pension plan and other postretirement benefit plan assets as of December 31, 2012 and 2011, along with the targeted mix of assets for each plan, is presented below:

	Target	2012	2011
Pension plan assets:			
Domestic equity	26 %	28 %	29 %
International equity	25	24	25
Fixed income	23	27	23
Special situations	3	1	—
Real estate investments	14	13	14
Private equity	9	7	9
Total	100 %	100 %	100 %
Other postretirement benefit plan assets:			
Domestic equity	40 %	38 %	39 %
International equity	21	24	18
Domestic fixed income	25	28	31
Global fixed income	4	3	4
Special situations	1	—	—
Real estate investments	6	5	5
Private equity	3	2	3
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, 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.

NOTES (continued)
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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, 2012 and 2011. 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:

- Investments in equity securities: 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.
- Investments in fixed income securities: 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.
- Investments in 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.
- Investments in private equity and real estate: 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.

NOTES (continued)
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The fair values of pension plan assets as of December 31, 2012 and 2011 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, 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:				
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.

NOTES (continued)
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As of December 31, 2011:	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*	$1,155	$533	$—	$1,688
International equity*	1,187	340	—	1,527
Fixed income:				
U.S. Treasury, government, and agency bonds	—	433	—	433
Mortgage- and asset-backed securities	—	135	—	135
Corporate bonds	—	832	3	835
Pooled funds	—	380	—	380
Cash equivalents and other	1	139	—	140
Real estate investments	220	—	782	1,002
Private equity	—	—	582	582
Total	$2,563	$2,792	$1,367	$6,722

* 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, 2012 and 2011 were as follows:

	2012 Real Estate Investments	Private Equity	2011 Real Estate Investments	Private Equity
	(in millions)			
Beginning balance	$782	$582	$674	$638
Actual return on investments:				
Related to investments held at year end	56	1	72	(12)
Related to investments sold during the year	3	41	20	47
Total return on investments	59	42	92	35
Purchases, sales, and settlements	—	(31)	16	(91)
Transfers into/out of Level 3	—	—	—	—
Ending balance	$841	$593	$782	$582

NOTES (continued)
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The fair values of other postretirement benefit plan assets as of December 31, 2012 and 2011 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, 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:				
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.

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As of December 31, 2011:	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*	$156	$38	$—	$194
International equity*	45	39	—	84
Fixed income:				
U.S. Treasury, government, and agency bonds	—	24	—	24
Mortgage- and asset-backed securities	—	5	—	5
Corporate bonds	—	32	—	32
Pooled funds	—	48	—	48
Cash equivalents and other	—	46	—	46
Trust-owned life insurance	—	291	—	291
Real estate investments	9	—	30	39
Private equity	—	—	23	23
Total	$210	$523	$53	$786

* 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, 2012 and 2011 were as follows:

	2012 Real Estate Investments (in millions)	Private Equity	2011 Real Estate Investments	Private Equity
Beginning balance	$30	$23	$26	$23
Actual return on investments:				
Related to investments held at year end	—	—	3	—
Related to investments sold during the year	—	1	1	2
Total return on investments	—	1	4	2
Purchases, sales, and settlements	—	(3)	—	(2)
Transfers into/out of Level 3	—	—	—	—
Ending balance	$30	$21	$30	$23

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 2012, 2011, and 2010 were $82 million, $78 million, and $76 million, respectively.

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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 byproducts, 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 a nontaxable $25 million payment from its insurance provider on June 14, 2012. Additionally, legal fees related to this insurance settlement totaled approximately $6 million. As a result, the net reduction to expense presented as MC Asset Recovery insurance settlement in the statement of income was approximately $19 million.

Environmental Matters

New Source Review Actions

In 1999, the EPA brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including Alabama Power and Georgia Power, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. The EPA alleged NSR violations at five coal-fired generating facilities operated by Alabama Power, including a unit co-owned by Mississippi Power, and three coal-fired generating facilities operated by Georgia Power, including a unit co-owned by Gulf Power. The civil action sought penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. The case against Georgia Power (including claims related to the unit co-owned by Gulf Power) was administratively closed in 2001 and has not been reopened. After Alabama Power was dismissed from the original action, the EPA filed a separate action in 2001 against Alabama Power (including claims related to the unit co-owned by Mississippi Power) in the U.S. District Court for the Northern District of Alabama.

In 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree, resolving claims relating to the alleged NSR violations at Plant Miller. In 2010, the EPA dismissed five of its eight remaining claims against Alabama Power, leaving only three claims, including one relating to the unit co-owned by Mississippi Power. In March 2011, the U.S. District Court for the Northern District of Alabama granted Alabama Power summary judgment on all remaining claims and dismissed the case with prejudice. That judgment is on appeal to the U.S. Court of Appeals for the Eleventh Circuit. On February 23, 2012, the EPA filed a motion in the U.S. District Court for the Northern District of Alabama seeking vacatur of the judgment and recusal of the judge in the case involving Alabama Power.

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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.

Climate Change Litigation

Kivalina Case

In 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs allege that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that some of the defendants (including Southern Company) acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. In 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case. On September 21, 2012, the U.S. Court of Appeals for the Ninth Circuit upheld the U.S. District Court for the Northern District of California's dismissal of the case. On November 27, 2012, the U.S. Court of Appeals for the Ninth Circuit denied the plaintiffs' request for review of the decision. On February 25, 2013, the plaintiffs filed a petition for writ of certiorari with the U.S. Supreme Court. Southern Company believes that these claims are without merit. While Southern Company believes the likelihood of loss is remote based on existing case law, it is not possible to predict with certainty whether Southern Company will incur any liability in connection with this matter. The ultimate outcome of this matter cannot be determined at this time.

Hurricane Katrina Case

In 2005, immediately following Hurricane Katrina, a lawsuit was filed in the U.S. District Court for the Southern District of Mississippi by Ned Comer on behalf of Mississippi residents seeking recovery for property damage and personal injuries caused by Hurricane Katrina. In 2006, the plaintiffs amended the complaint to include Southern Company and many other electric utilities, oil companies, chemical companies, and coal producers. The plaintiffs allege that the defendants contributed to climate change, which contributed to the intensity of Hurricane Katrina. In 2007, the U.S. District Court for the Southern District of Mississippi dismissed the case. On appeal to the U.S. Court of Appeals for the Fifth Circuit, a three-judge panel reversed the U.S. District Court for the Southern District of Mississippi, holding that the case could proceed, but, on rehearing, the full U.S. Court of Appeals for the Fifth Circuit dismissed the plaintiffs' appeal, resulting in reinstatement of the decision of the U.S. District Court for the Southern District of Mississippi in favor of the defendants. In May 2011, the plaintiffs filed an amended version of their class action complaint, arguing that the earlier dismissal was on procedural grounds and under Mississippi law the plaintiffs have a right to re-file. The amended complaint was also filed against numerous chemical, coal, oil, and utility companies, including Alabama Power, Georgia Power, Gulf Power, and Southern Power. On March 20, 2012, the U.S. District Court for the Southern District of Mississippi dismissed the plaintiffs' amended complaint. On April 16, 2012, the plaintiffs appealed the case to the U.S. Court of Appeals for the Fifth Circuit. Southern Company believes that these claims are without merit. While Southern Company believes the likelihood of loss is remote based on existing case law, it is not possible to predict with certainty whether the Company will incur any liability in connection with this matter. The ultimate outcome of this matter 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, 2012 was $19 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 large 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 on the Georgia Hazardous Sites Inventory and the CERCLA NPL

NOTES (continued)
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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 September 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. In November 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 November 2011 that it is considering enforcement options against Georgia Power and other non-complying UAO recipients. If 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 court granted Georgia Power's summary judgment motion ruling that Georgia Power has no liability in the private action. The plaintiffs may appeal the court'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 treatment, 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 $61 million as of December 31, 2012. 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 estimates.

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 substantially all 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 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 accrue until the issue is resolved or storage is provided. No amounts have been recognized in the financial statements as of December 31, 2012 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.

Sufficient pool storage capacity for spent fuel is available at Plant Vogtle Units 1 and 2 to maintain full-core discharge capability for both units into 2014. Construction of an on-site dry storage facility at Plant Vogtle Units 1 and 2 has begun. The facility is expected to begin operation in sufficient time to maintain full-core discharge capability, with additional on-site dry storage to be added as needed. At Plants Hatch and Farley, on-site dry spent fuel storage facilities are operational and can be expanded to accommodate spent fuel through the expected life of each plant.

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Retail Regulatory Matters
Alabama Power
Retail Rate Adjustments
In July 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 April 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%. Retail rates remain unchanged when the retail return on common equity (ROE) is projected to be between 13.0% and 14.5%. If Alabama Power's actual retail ROE 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 ROE fall below the allowed equity return range.
In 2011 and 2012, retail rates under Rate RSE remained unchanged from 2010. On November 30, 2012, Alabama Power made its Rate RSE submission to the Alabama PSC of projected data for calendar year 2013; projected earnings were within the specified return range, and, therefore, retail rates under Rate RSE remained unchanged for 2013. Under the terms of Rate RSE, the maximum possible increase for 2014 is 5.00%. However, Alabama Power is working with the Alabama PSC to develop a plan that will potentially preclude the need for a Rate RSE increase in 2014. The ultimate outcome of this matter cannot be determined at this time.
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). Effective April 2011, Rate CNP PPA was reduced by approximately $5 million annually. On March 6, 2012, 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, 2012 through March 31, 2013. It is anticipated that no adjustment will be made to Rate CNP PPA in 2013. As of December 31, 2012, Alabama Power had an under recovered certificated PPA balance of $9 million, $7 million of which is included in deferred under recovered regulatory clause revenues and $2 million of which is included in under recovered regulatory clause revenues in the balance sheet.
On September 17, 2012, the Alabama PSC approved and certificated a PPA for the purchase of approximately 200 megawatts (MWs) of the approximately 400 MWs of energy from wind-powered generating facilities and all associated environmental attributes, including renewable energy credits. The terms of this PPA and a previously approved and certificated PPA 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, to third parties. Approximately 200 MWs of energy from wind-powered generating facilities was operational in December 2012.
Alabama Power's retail rates, approved by the Alabama PSC also allow 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 to recover environmental costs in 2011 or 2012. On November 26, 2012, 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 less than $1 million, which is to be recovered in the billing months of January 2013 through December 2013. On December 4, 2012, the Alabama PSC issued a consent order that Alabama Power leave in effect for 2013 the factors associated with Alabama Power's environmental compliance costs for the year 2012. Any unrecovered amounts associated with 2013 will be reflected in the 2014 filing. As of December 31, 2012, Alabama Power had an under recovered environmental clause balance of $21 million which is included in under recovered regulatory clause revenues in the balance sheet.

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Environmental Accounting Order

Proposed and final environmental regulations could result in significant additional compliance costs that could affect future unit retirement and replacement decisions. In September 2011, the Alabama PSC approved an order allowing for the establishment of a regulatory asset to record the unrecovered investment costs associated with any such decisions, including the unrecovered plant asset balance and the unrecovered costs associated with site removal and closure. 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

On November 6, 2012, the Alabama PSC approved an accounting order for certain compliance-related operation and maintenance expenditures for the years 2013 through 2017, as well as the incremental increase in operation expense related to pension cost for 2013. Under the accounting order, expenses from January 2013 through December 2017 related to compliance with standards addressing Critical Infrastructure Protection issued by the North American Electric Reliability Corporation and cyber security requirements issued by the NRC will be deferred to a regulatory asset account and amortized over a three-year period beginning in January 2015. Expenses from January 2013 through December 2017 related to compliance with NRC guidance addressing the readiness at nuclear facilities within the U.S., as prompted by the earthquake and tsunami that struck Japan in March 2011, also will be deferred as a regulatory asset and recovered over the same amortization period. The compliance-related expenses to be afforded regulatory asset treatment over the five-year period are currently estimated to be approximately $43 million. In addition, the accounting order authorizes Alabama Power to defer an incremental increase in its pension cost for 2013. That increased pension cost is estimated to be approximately $17 million. During 2013, the actual incremental increase will be deferred to a regulatory asset account and will be amortized over a three-year period beginning in January 2015. Pursuant to the accounting order, Alabama Power has the ability to accelerate the amortization of the regulatory assets.

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 4, 2012, the Alabama PSC issued a consent order that Alabama Power leave in effect the energy cost recovery rates which began in April 2011 for 2013. Therefore, the Rate ECR factor as of January 1, 2013 remained at 2.681 cents per KWH. Effective with billings beginning in January 2014, the Rate ECR factor will be 5.910 cents per KWH, absent a further order from the Alabama PSC.

As of December 31, 2012 and 2011, Alabama Power had under recovered fuel balances of approximately $4 million and $31 million, respectively, which are included in deferred under recovered regulatory clause revenues in the balance sheets. This classification is 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. 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

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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.

During the first half of 2011, multiple storms caused varying degrees of damage to Alabama Power's transmission and distribution facilities. The most significant storms occurred in April 2011, causing over 400,000 of Alabama Power's 1.4 million customers to be without electrical service. The cost of repairing the damage to facilities and restoring electrical service to customers as a result of these storms was $42 million for operations and maintenance expenses and $161 million for capital-related expenditures.

In accordance with the order that was issued by the Alabama PSC in July 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, 2012 and December 31, 2011 were approximately $103 million and $110 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 2010, the Alabama PSC approved a change to the nuclear maintenance outage accounting process associated with routine refueling activities. Previously, Alabama Power accrued nuclear outage operations and maintenance expenses for the two units at Plant Farley during the 18-month cycle for the outages. In accordance with the 2010 order, nuclear outage expenses are deferred when the charges actually occur and then amortized over the subsequent 18-month period.

The initial result of implementation of the accounting order was that no nuclear maintenance outage expenses were recognized from January 2011 through December 2011, which decreased nuclear outage operations and maintenance expenses in 2011 from 2010 by approximately $50 million. During the fall of 2011, approximately $38 million of actual nuclear outage expenses associated with one unit at Plant Farley was deferred to a regulatory asset account; beginning in January 2012, these deferred costs are being amortized to nuclear operations and maintenance expenses over an 18-month period. During the spring of 2012, approximately $31 million of actual nuclear outage expenses associated with the second unit at Plant Farley was deferred to a regulatory asset account; beginning in July 2012, these deferred costs are being amortized to nuclear operations and maintenance expenses 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 existing order.

Georgia Power

Rate Plans

The economic recession significantly reduced Georgia Power's revenues upon which retail rates were set by the Georgia PSC for 2008 through 2010 (2007 Retail Rate Plan). In 2009, despite stringent efforts to reduce expenses, Georgia Power's projected retail ROE for both 2009 and 2010 was below 10.25%. However, in lieu of a full base rate case to increase customer rates as allowed under the 2007 Retail Rate Plan, in 2009, the Georgia PSC approved Georgia Power's request for an accounting order. Under the terms of the accounting order, Georgia Power could amortize up to $108 million of the regulatory liability related to other cost of removal obligations in 2009 and up to $216 million in 2010, limited to the amount needed to earn no more than a 9.75% and 10.15% retail ROE in 2009 and 2010, respectively. For the years ended December 31, 2009 and 2010, Georgia Power amortized $41 million and $174 million, respectively, of the regulatory liability related to other cost of removal obligations.

In 2010, the Georgia PSC approved the 2010 ARP, which became effective January 1, 2011. The terms of the 2010 ARP reflect a settlement agreement among Georgia Power, the Georgia PSC Public Interest Advocacy Staff, and eight other intervenors. Under the terms of the 2010 ARP, Georgia Power is amortizing approximately $92 million of its remaining regulatory liability related to other cost of removal obligations over the three years ending December 31, 2013.

Also under the terms of the 2010 ARP, effective January 1, 2011, Georgia Power increased its (1) traditional base tariff rates by approximately $347 million; (2) Demand-Side Management (DSM) tariff rates by approximately $31 million; (3) environmental compliance cost recovery tariff rate by approximately $168 million; and (4) Municipal Franchise Fee (MFF) tariff rate by approximately $16 million, for a total increase in base revenues of approximately $562 million.

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Under the 2010 ARP, the following additional base rate adjustments have been made to Georgia Power's tariffs in 2012 and 2013:

- Effective January 1, 2012 and 2013, the DSM tariffs increased by $17 million and $14 million, respectively;
- Effective April 1, 2012 and January 1, 2013, the traditional base tariffs increased by an estimated $122 million and $58 million, respectively, to recover the revenue requirements for Plant McDonough-Atkinson Units 4, 5, and 6 for the period through December 31, 2013; and
- The MFF tariff increased consistently with the adjustments above, as well as those related to the interim fuel rider (IFR) and Nuclear Construction Cost Recovery (NCCR) tariff adjustments described herein under "Fuel Cost Recovery" and "Nuclear Construction."

Under the 2010 ARP, Georgia Power's allowed retail ROE is set at 11.15%, and earnings will be evaluated against a retail ROE range of 10.25% to 12.25%. Two-thirds of any earnings above 12.25% will be directly refunded to customers, with the remaining one-third retained by Georgia Power. There were no refunds related to earnings for 2011 or 2012. Georgia Power is required to file a general base rate case by July 1, 2013, in response to which the Georgia PSC would be expected to determine whether the 2010 ARP should be continued, modified, or discontinued.

Integrated Resource Plans

On March 20, 2012, the Georgia PSC approved Georgia Power's request to decertify and retire Plant Branch Units 1 and 2 as of December 31, 2013 and October 31, 2013, the compliance dates for the respective units under the Georgia Multi-Pollutant Rule, and an oil-fired unit at Plant Mitchell as of March 26, 2012, as requested in the 2011 Integrated Resource Plan (IRP). The Georgia PSC also approved three PPAs totaling 998 MWs with Southern Power for capacity and energy that will commence in 2015 and end in 2030. On November 21, 2012, the FERC accepted the PPAs.

Separately, on March 20, 2012, the Georgia PSC certified 495 MWs of wholesale capacity to be returned to retail service in 2015 and 2016 under a 2010 agreement, subject to the decertification of any related generating units including 243 MWs of the 16 units described below.

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.

Georgia Power requested the decertification of Plant Boulevard Units 2 and 3 (28 MWs) upon approval of the 2013 IRP and the decertification of Plant Bowen Unit 6 (32 MWs) by April 16, 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 retired by April 16, 2015, the compliance date of the Mercury and Air Toxics Standards (MATS) rule. Georgia Power has also requested a revision to the decertification date of Plant Branch Unit 1 from December 31, 2013 to April 16, 2015. To allow for necessary transmission reliability improvements, Georgia Power expects to seek a one-year extension of the MATS rule compliance date for Plant Kraft Units 1 through 4 (316 MWs) and to retire these units by April 16, 2016. The filing also included Georgia Power's request to switch the primary fuel source for Plant Yates Units 6 and 7 from coal to natural gas. Additionally, Georgia Power plans to switch the primary fuel source for Plant McIntosh Unit 1 from Central Appalachian coal to Powder River Basin (PRB) coal following further evaluation, including a successful test burn of the PRB fuel.

Under the terms of the 2010 ARP, any costs associated with changes to Georgia Power's approved environmental operating or capital budgets resulting from new or revised environmental regulations through 2013 that are approved by the Georgia PSC in connection with an updated IRP will be deferred as a regulatory asset to be recovered over a time period deemed appropriate by the Georgia PSC. In connection with the retirement decisions, Georgia Power reclassified the retail portion of the net carrying value of Plant Branch Units 1 through 4 from plant in service, net of depreciation, to other utility plant, net. Georgia Power is continuing to depreciate these units using the current composite straight-line rates previously approved by the Georgia PSC. Upon actual retirement, the Georgia PSC approved the continued deferral and amortization of the remaining net carrying values for Plant Branch Units 1 and 2 in its order for the 2011 IRP and Georgia Power has requested similar treatment for Plant Branch Units 3 and 4 in the 2013 IRP. Georgia Power also reclassified the construction work in progress (CWIP) balances totaling $65 million related to environmental controls for Plant Branch Units 1 through 4 and Plant Yates Units 6 and 7 that will not be completed as a result of the retirement decisions to regulatory assets and ceased accruing AFUDC. The Georgia PSC approved a three-year amortization period beginning January 2014 for the $13 million balance relating to Plant Branch Units 1 and 2 in its order for the 2011 IRP and Georgia Power has requested similar treatment for the balances related to Plant Branch Units 3 and 4 and Plant Yates Units 6 and 7 in the 2013 IRP. Georgia Power has also requested that the Georgia PSC approve the deferral of the

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costs associated with material and supplies remaining at the unit retirement dates to a regulatory asset, to be amortized over a time period deemed appropriate by the Georgia PSC. As a result of this regulatory treatment, the decertification of these units is not expected to have a material impact on Southern Company's financial statements. The Georgia PSC is scheduled to vote on the 2013 IRP by July 2013.

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. In addition, the Georgia PSC has authorized an IFR, which allows Georgia Power to adjust its fuel cost recovery rates prior to the next fuel case if the under or over recovered fuel balance exceeds $215 million through February 2013 and $200 million thereafter. 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. Georgia Power expects to file its next fuel case by March 1, 2014.

Georgia Power's over recovered fuel balance totaled approximately $230 million at December 31, 2012 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, 2012, the balance in the regulatory asset related to storm damage was $38 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 (Vogtle 3 and 4 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 (Plant Vogtle Units 3 and 4). 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 and, at certain stages of the work, cancellation fees to the Contractor. 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 Georgia PSC originally certified construction costs of $6.4 billion to place Plant Vogtle Units 3 and 4 into service in April 2016 and April 2017, respectively, and approved inclusion of the related CWIP accounts in rate base. Also in 2009, the State of Georgia enacted the Georgia Nuclear Energy Financing Act, which allows Georgia Power to recover financing costs for nuclear construction projects through annual adjustments to an NCCR tariff by including the related CWIP accounts in rate base during the construction period. With respect to Plant Vogtle Units 3 and 4, this legislation allowed Georgia Power, beginning in 2011, to recover an estimated $1.7 billion of related financing costs during the construction period. As a result, in 2009, the Georgia PSC also revised the certified in-service capital cost to approximately $4.4 billion.

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The Georgia PSC approved increases to the NCCR tariff of approximately $223 million, $35 million, and $50 million, effective January 1, 2011, 2012, and 2013, 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, 2012, approximately $55 million of these 2009 and 2010 costs remained unamortized in CWIP. At December 31, 2012, Georgia Power's CWIP balance for Plant Vogtle Units 3 and 4 totaled $2.3 billion.

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) on February 10, 2012. Receipt of the COLs allowed full construction to begin.

On February 16, 2012, separate groups of petitioners filed petitions in the U.S. Court of Appeals for the District of Columbia Circuit seeking judicial review of the NRC's issuance of the COLs and certification of the DCD. These petitions were consolidated on April 3, 2012. On April 18, 2012, another group of petitioners filed a motion to stay the effectiveness of the COLs with the U.S. District Court for the District of Columbia. On July 11, 2012, the U.S. Court of Appeals for the District of Columbia Circuit denied the petitioners' motion to stay the effectiveness of the COLs. Georgia Power has intervened in, and intends to vigorously contest, these petitions. Additional technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4, at the federal and state level, 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 each year. On February 19, 2013, the Georgia PSC voted to approve Georgia Power's seventh VCM report, including construction capital costs incurred through June 30, 2012 of approximately $2.0 billion. Georgia Power's eighth VCM report requests approval for an additional $0.2 billion of construction capital costs incurred through December 31, 2012. 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, the eighth VCM also requests an amendment to the certificate to increase the estimated in-service capital cost of Plant Vogtle Units 3 and 4 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. Associated financing costs during the construction period are estimated to total approximately $2.0 billion.

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 Contractor has claimed that its estimated adjustment attributable to Georgia Power (based on Georgia Power's ownership interest) is approximately $425 million (in 2008 dollars) with respect to these issues. 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. On November 1, 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 on November 1, 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. While litigation has commenced and Georgia Power intends to vigorously defend its positions, Georgia Power 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.

In addition, there are processes in place that are designed to assure compliance with the requirements specified in the DCD and the COLs, including rigorous inspections by Southern Nuclear and the NRC that occur throughout construction. During the fourth quarter 2012, certain details of the rebar design for the Plant Vogtle Unit 3 nuclear island were evaluated for consistency with the DCD and a few non-safety-related deviations were identified. On January 15, 2013 and January 18, 2013, Southern Nuclear submitted two license amendment requests to conform the rebar design details to NRC requirements. On January 29, 2013, the NRC issued "no objection" letters in response to the related preliminary amendment requests, enabling completion of final work supporting the pouring of base mat concrete, which is expected to occur following approval of the license amendment requests in March 2013. Various design and other issues are expected to arise as construction proceeds, which may result in additional license amendments or require other resolution. If any license amendment requests 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.

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As construction continues, additional delays in the fabrication and assembly of structural modules, the failure of such modules to meet applicable standards, or other issues 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.
Integrated Coal Gasification Combined Cycle
General
Mississippi Power is constructing a new electric generating facility located in Kemper County, Mississippi which will utilize an integrated coal gasification combined cycle technology with an output capacity of 582 MWs (Kemper IGCC). The Kemper IGCC will use as fuel locally mined lignite (an abundant, lower heating value coal) from a mine owned by Mississippi Power and situated adjacent to the Kemper IGCC. In connection with the Kemper IGCC, Mississippi Power also plans to construct and operate approximately 61 miles of CO_2 pipeline infrastructure. The Kemper IGCC is scheduled to be placed in-service in May 2014.
In 2010, the Mississippi PSC issued a certificate of public convenience and necessity (CPCN) authorizing the acquisition, construction, and operation of the Kemper IGCC (2010 MPSC Order). The Sierra Club filed an appeal of the Mississippi PSC's issuance of the CPCN and, on March 15, 2012, the Mississippi Supreme Court reversed the decision of the Chancery Court of Harrison County, Mississippi (Chancery Court) upholding the 2010 MPSC Order and remanded the matter to the Mississippi PSC. The Mississippi Supreme Court concluded that the 2010 MPSC Order did not cite in sufficient detail substantial evidence upon which the Mississippi Supreme Court could determine the basis for the findings of the Mississippi PSC granting the CPCN. On March 30, 2012, the Mississippi PSC issued a temporary authorization which allowed Mississippi Power to continue construction and, on April 24, 2012, issued a detailed order (2012 MPSC Order) confirming the CPCN for the Kemper IGCC. On April 26, 2012, the Sierra Club appealed the 2012 MPSC Order to the Chancery Court. On December 17, 2012, the Chancery Court affirmed the 2012 MPSC Order which confirmed the issuance of the CPCN for the Kemper IGCC. On January 8, 2013, the Sierra Club filed an appeal of the Chancery Court's ruling with the Mississippi Supreme Court.
The certificated cost estimate of the Kemper IGCC included in the 2012 MPSC 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 (CCPI2) and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, and financing costs related to the Kemper IGCC. The 2012 MPSC 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. Exemptions from the cost cap included in the 2012 MPSC Order included the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, financing costs, 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).
Mississippi Power's current cost estimate for the Kemper IGCC (net of the $245 million CCPI2 grant, and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, financing costs, and certain general exceptions as contemplated in the 2012 MPSC Order and the settlement agreement between Mississippi Power and the Mississippi PSC entered into on January 24, 2013 (Settlement Agreement) that must be specifically approved by the Mississippi PSC) is approximately $2.88 billion. The Mississippi PSC and the Mississippi Public Utilities Staff (MPUS) have engaged their independent monitors to assess the current cost estimates and schedule projections for the Kemper IGCC. These consultants have issued reports with their own opinions as to the likelihood that costs for the Kemper IGCC will remain at or under the $2.88 billion cost cap and as to the expected in-service date. While Mississippi Power continues to believe its cost estimate and schedule projection remain appropriate based on the

current status of the project, it is possible that Mississippi Power could experience further cost increases and/or schedule delays with respect to the Kemper IGCC. Certain factors have caused and may continue to cause the costs for the Kemper IGCC to increase and/or schedule delays to occur including, but not limited to, costs and productivity of labor, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay or non-performance under construction or other agreements, and unforeseen engineering problems. To the extent it becomes probable that costs beyond any permitted exceptions to the cost cap will exceed $2.88 billion or it becomes probable that the Mississippi PSC will disallow a portion of the costs relating to the Kemper IGCC, including certain general exceptions as contemplated in the 2012 MPSC Order and the Settlement Agreement, charges to expense may occur and these charges could be material. See "Cost Recovery Plans" below for additional information relating to the Settlement Agreement that defines the process for resolving matters regarding cost recovery related to the Kemper IGCC.

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As of December 31, 2012, Mississippi Power had spent a total of $2.51 billion on the Kemper IGCC, including the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, and other deferred costs. Of this total, $2.47 billion was included in CWIP (which is net of $245 million of CCPI2 grant funds), $35 million was recorded in other regulatory assets, $4 million was recorded in other deferred charges and assets, and $1 million was previously expensed. 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. This includes deferred costs associated with the generation resource planning, evaluation, and screening activities. The amortization period for the regulatory asset 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.

The 2012 MPSC Order established periodic prudence reviews during the annual CWIP review process. Of the total costs of $51 million incurred through March 2009, $46 million has been reviewed and deemed prudent by the Mississippi PSC. Due to the decision of the Mississippi PSC to deny the Certificated New Plant-A (CNP-A) rate filing and a 2012 rate request related to the Kemper IGCC described below, prudence reviews for the construction costs of the Kemper IGCC incurred after March 2009 have not been made. The Settlement Agreement provides for completion of all prudence reviews within six months of the date the Kemper IGCC is placed in service. See "Cost Recovery Plans" herein for additional information.

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

Cost Recovery Plans

The 2012 MPSC 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. In the 2012 MPSC Order, the Mississippi PSC approved financing cost recovery on CWIP balances not to exceed the $2.4 billion certificated cost estimate for the Kemper IGCC. The 2012 MPSC Order provided for the accrual of AFUDC in 2010 and 2011 and for the current recovery of financing costs on 100% of CWIP in 2012, 2013, and through May 1, 2014 (provided that the amount of financing cost recovery allowed is to be reduced by the amount of certain state and federal government construction cost incentives received by Mississippi Power and must be justified by a showing that such recovery will benefit customers over the life of the Kemper IGCC). With respect to recovery of costs following the in-service date of the Kemper IGCC, the 2012 MPSC Order provided for the establishment of operational cost and revenue parameters based upon assumptions in Mississippi Power's petition for the CPCN.

On June 1, 2012, the MPUS signed a joint stipulation with Mississippi Power to establish a proposed rate schedule detailing CNP-A and, on June 14, 2012, Mississippi Power submitted to the Mississippi PSC a filing to establish the new CNP-A rate schedule and a stipulated rate increase based upon the revenue request of between $55 million and $59 million to recover financing costs over the remainder of 2012. On June 22, 2012, the Mississippi PSC denied the proposed CNP-A rate schedule and the 2012 rate recovery filings submitted by Mississippi Power, 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.

On July 9, 2012, Mississippi Power appealed the Mississippi PSC's June 22, 2012 decision to the Mississippi Supreme Court and requested interim rates under bond of $55 million. On July 31, 2012, the Mississippi Supreme Court denied Mississippi Power's request for interim rates under bond until the Mississippi Supreme Court decides Mississippi Power's appeal of the Mississippi PSC's June 22, 2012 decision.

On January 24, 2013, Mississippi Power and the Mississippi PSC entered into the Settlement Agreement that (1) establishes the process for resolving matters regarding cost recovery related to the Kemper IGCC for the purpose of mitigating risks to Mississippi Power and its customers and expediting the regulatory process associated with future rate filings required under the Settlement Agreement and (2) resolves Mississippi Power's CNP-A rate appeal before the Mississippi Supreme Court.

On February 12, 2013, the Mississippi Supreme Court granted Mississippi Power and the Mississippi PSC's joint filing for dismissal of Mississippi Power's appeal of the Mississippi PSC's June 22, 2012 decision.

Under the terms of the Settlement Agreement, Mississippi Power and the Mississippi PSC will follow certain agreed-upon regulatory procedures and schedules for resolving the cost recovery matters related to the Kemper IGCC. These procedures and schedules include the following: (1) Mississippi Power's filing within 30 days of the Settlement Agreement of a new request to increase rates in 2013 in an amount not to exceed a $172 million annual revenue requirement, based upon projected investment as December 31, 2013, to be recorded to a regulatory liability to be used to mitigate rate impacts when the Kemper IGCC is placed in service (which filing for $172 million was made on January 25, 2013); (2) the Mississippi PSC's decision on that matter within 50 days of Mississippi Power's request; (3) Mississippi Power's collaboration with the MPUS to file with the Mississippi PSC within three months of the Settlement Agreement 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 (which filing was made on February 26, 2013 as described below); (4) the Mississippi PSC's decision on the rate recovery plan within four months of that filing; (5) Mississippi Power's agreement to limit the portion of prudently-incurred Kemper IGCC costs to be included in rate base to the $2.4 billion certificated cost estimate, plus costs related to the lignite mine and CO_2 pipeline as well as any other costs permitted or determined to be excluded from the cost cap, provided that this limitation will not prevent Mississippi Power from securing alternate financing to recover any prudently-incurred Kemper IGCC costs, including financing costs and plant costs above the $2.4 billion certificated cost estimate, not otherwise recovered in any Mississippi PSC rate proceeding contemplated by the Settlement Agreement; and (6) the Mississippi PSC's completion of its prudence review of the Kemper IGCC costs incurred through 2012 within six months of the Settlement Agreement, an additional prudence review upon considering the seven-year rate plan for costs incurred through the most recent reporting period, and a final prudence review of the remaining project costs within six months of the Kemper IGCC's in-service date.

Legislation to authorize a multi-year rate plan and legislation to provide for alternate financing through securitization was passed in the Mississippi legislature and was signed by the Governor on February 26, 2013. Mississippi Power contemplates using securitization as provided in the legislation as its form of alternate financing for prudently-incurred Kemper IGCC costs, including financing costs and plant costs above the $2.4 billion certificated cost estimate, not otherwise recovered in any Mississippi PSC rate proceeding contemplated by the Settlement Agreement.

On February 26, 2013, Mississippi Power, in compliance with the Settlement Agreement, filed with the Mississippi PSC a rate recovery plan for the Kemper IGCC for 2014 through 2020, the first seven years of operation of the Kemper IGCC. The rate recovery plan proposes recovery of an annual revenue requirement of approximately $150 million of Kemper IGCC-related operational costs and rate base amounts, including plant costs equal to the $2.4 billion certificated cost estimate. Approval of Mississippi Power's request to increase rates in 2013 to mitigate the rate impacts of the Kemper IGCC filed on January 25, 2013 is integral to the rate recovery plan as the proposed filing contemplates amortization of the regulatory liability to be used to mitigate rate impacts from 2014 through 2020, based on a fixed amortization schedule that requires approval by the Mississippi PSC. Under the rate recovery plan filing, Mississippi Power proposes annual recovery to remain the same from 2014 through 2020 and, while it is the intent of Mississippi Power for the actual revenue requirement to equal the proposed revenue requirement for certain items, Mississippi Power proposes that the annual differences for those items through 2020 will be deferred, subject to accrual of carrying costs, and the cumulative balance will be reviewed at the end of the term of the Settlement Agreement by the Mississippi PSC for determination of the manner of the recovery. Mississippi Power proposes to secure recovery of prudently-incurred Kemper IGCC costs, including financing costs and plant costs above the $2.4 billion certificated cost estimate, not otherwise recovered in any Mississippi PSC rate proceeding contemplated by the Settlement Agreement to be provided for with alternate financing through securitization. The rate recovery necessary to recover the annual costs of securitization is proposed to be filed and begin after the Kemper IGCC is placed in service.

Under the terms of the Settlement Agreement, Mississippi Power has the right to terminate the Settlement Agreement if certain conditions, including the passage of multi-year rate plan legislation that is contemplated under the Settlement Agreement, 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.

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

Tax Incentives

The IRS has 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. Mississippi Power's utilization of Phase I and Phase II credits is dependent upon meeting the IRS certification requirements, including an in-service date no later than May 11, 2014 for the Phase I credits and April 19, 2016 for the Phase II credits. In order to remain eligible for the Phase II credits, Mississippi Power plans to capture and sequester (via enhanced oil recovery) at least 65% of the CO_2 produced by the Kemper IGCC during operations in accordance with the rules for Section 48A investment tax credits. Through December 31, 2012, Mississippi Power received or accrued tax benefits totaling $362 million for these tax credits, which will be amortized as a reduction to depreciation and amortization over the life of the Kemper IGCC. As a result of bonus tax depreciation on certain assets placed, or to be placed, in service in 2012 and 2013, and the subsequent reduction in federal taxable income, Mississippi Power estimates that it will not be

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able to utilize $171 million of these tax credits until after 2013. IRS guidelines allow these unused tax credits to be carried forward for 20 years, expiring at the end of 2031, if not utilized before then. On October 15, 2012, Mississippi Power filed an application with the DOE for certification of the Kemper IGCC for additional tax credits under the Internal Revenue Code Section 48A (Phase III). A portion of the tax credits realized by Mississippi Power may be subject to recapture upon successful completion of South Mississippi Electric Power Association's (SMEPA) purchase of an undivided interest in the Kemper IGCC as described below. In addition, all or a portion of the tax credits will be subject to recapture if Mississippi Power fails to satisfy the in-service date requirements and carbon capture requirements described above.

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 50% bonus depreciation for property to be 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.

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

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 in Kemper County. The mine is scheduled to be placed in service in June 2013. The estimated capital cost of the mine is approximately $245 million, of which $163 million has been incurred through December 31, 2012.

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. Because Liberty Fuels conducts all of its activities on behalf of Mississippi Power, Liberty Fuels qualifies as a VIE for which Mississippi Power is the primary beneficiary. 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. Consistent with the requirements of consolidation accounting, Liberty Fuels is consolidated in the financial statements of Mississippi Power and accordingly the asset retirement cost and the asset retirement obligation have been recorded in Mississippi Power's financial statements. In addition to the obligation to fund the reclamation activities, Mississippi Power currently provides working capital support to Liberty Fuels through cash advances for capital purchases, payroll, and other operating expenses.

In addition, Mississippi Power 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 estimated capital cost of the CO_2 pipeline facilities is approximately $132 million, of which $78 million has been incurred through December 31, 2012.

The ultimate outcome of these matters, including the determinations of prudency and the specific manner of recovery of prudently-incurred costs relating to the Kemper IGCC, is subject to further regulatory actions and 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. On February 28, 2012, the Mississippi PSC approved the sale and transfer of 17.5% of the Kemper IGCC to SMEPA. On June 29, 2012, Mississippi Power and SMEPA signed an amendment to the asset purchase agreement whereby SMEPA extended its option to purchase until December 31, 2012 and 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 December 31, 2012, Mississippi Power and SMEPA agreed to extend SMEPA's option to purchase through December 31, 2013.

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. On September 27, 2012, SMEPA received a conditional loan commitment from Rural Utilities Service to provide funding for SMEPA's undivided interest in the Kemper IGCC.

On March 6, 2012, Mississippi Power received a $150 million interest-bearing refundable deposit from SMEPA to be applied to the purchase. While the expectation is that the amount will be applied to the purchase price at closing, Mississippi Power would be required to refund the deposit 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 Services, 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 deposit has been presented as a current liability in Southern Company's balance sheet herein and as financing proceeds in Southern Company's statement of cash flows herein.

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

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 will depend on the outcome of any legal challenges and cannot be determined at this time. See "Cost Recovery Plans" herein for additional information regarding certain legislation related to the Kemper IGCC.

4. JOINT OWNERSHIP AGREEMENTS

Alabama Power owns an undivided interest in Units 1 and 2 at Plant Miller and related facilities jointly with Power South Energy Cooperative, Inc. Georgia Power owns undivided interests in Plants Vogtle, Hatch, Scherer, and Wansley in varying amounts jointly with 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 Florida Power Corporation 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, 2012, 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	%	$3,327	$1,996	$67
Plant Hatch (nuclear)	50.1		1,037	551	49
Plant Miller (coal) Units 1 and 2	91.8		1,401	551	8
Plant Scherer (coal) Units 1 and 2	8.4		161	78	77
Plant Wansley (coal)	53.5		801	240	8
Rocky Mountain (pumped storage)	25.4		181	116	—
Intercession City (combustion turbine)	33.3		12	4	1
Plant Stanton (combined cycle) Unit A	65.0		156	36	—

Georgia Power also owns 45.7% of Plant Vogtle Units 3 and 4 that are currently under construction. See Note 3 to the financial statements 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.

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5. INCOME TAXES

Southern Company files a consolidated federal income tax return and combined state income tax returns for the States of Alabama, Georgia, Mississippi, and Texas. Under a joint consolidated income tax allocation agreement, each 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:

	2012	2011	2010
	(in millions)		
Federal —			
Current	$177	$57	$42
Deferred	1,011	1,035	898
	1,188	1,092	940
State —			
Current	61	8	(54)
Deferred	85	119	140
	146	127	86
Total	$1,334	$1,219	$1,026

Net cash payments/(refunds) for income taxes in 2012, 2011, and 2010 were $38 million, $(401) million, and $276 million, respectively.

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

	2012	2011
	(in millions)	
Deferred tax liabilities —		
Accelerated depreciation	$9,022	$7,882
Property basis differences	1,254	1,256
Leveraged lease basis differences	278	277
Employee benefit obligations	536	499
Under recovered fuel clause	16	82
Premium on reacquired debt	84	111
Regulatory assets associated with employee benefit obligations	988	1,198
Regulatory assets associated with asset retirement obligations	1,108	546
Other	333	276
Total	13,619	12,127
Deferred tax assets —		
Federal effect of state deferred taxes	394	393
Employee benefit obligations	1,678	1,594
Over recovered fuel clause	135	33
Other property basis differences	134	134
Deferred costs	39	55
Cost of removal	29	40
Tax credit carryforward	256	129
Unbilled revenue	101	110
Other comprehensive losses	84	81
Asset retirement obligations	720	546
Other	362	358
Total	3,932	3,473
Total deferred tax liabilities, net	9,687	8,654
Portion included in prepaid expenses (accrued income taxes), net	237	125
Deferred state tax assets	68	86
Valuation allowance	(54)	(56)
Accumulated deferred income taxes	$9,938	$8,809

At December 31, 2012, Southern Company had subsidiaries with State of Georgia net operating loss (NOL) carryforwards totaling $827 million, which could result in net state income tax benefits of $48 million, if utilized. However, the subsidiaries have established a valuation allowance for the potential $48 million tax benefit due to the remote likelihood that the tax benefit will be realized. These NOLs expire between 2013 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, 2012, the tax-related regulatory assets to be recovered from customers were $1.4 billion. 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, 2012, the tax-related regulatory liabilities to be credited to customers were $211 million. These liabilities are primarily attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and to unamortized investment tax credits.

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In accordance with regulatory requirements, deferred investment tax credits 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 $23 million in 2012, $19 million in 2011, and $23 million in 2010. At December 31, 2012, all investment tax credits available to reduce federal income taxes payable had not been utilized. The remaining investment tax credits 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 to be placed in service in 2013). The application of the bonus depreciation provisions in the Tax Relief Act significantly increased deferred tax liabilities related to accelerated depreciation.

Effective Tax Rate

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

	2012		2011		2010	
Federal statutory rate	35.0	%	35.0	%	35.0	%
State income tax, net of federal deduction	2.5		2.4		1.8	
Employee stock plans dividend deduction	(1.0	)	(1.1	)	(1.2	)
Non-deductible book depreciation	0.9		0.7		0.8	
Difference in prior years' deferred and current tax rate	(0.1	)	(0.1	)	(0.1	)
AFUDC-Equity	(1.3	)	(1.5	)	(2.2	)
ITC basis difference	(0.3	)	(0.2	)	(0.4	)
Other	(0.1	)	(0.2	)	(0.2	)
Effective income tax rate	35.6	%	35.0	%	33.5	%

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

Unrecognized Tax Benefits

For 2012, the total amount of unrecognized tax benefits decreased by $50 million, resulting in a balance of $70 million as of December 31, 2012.

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

	2012		2011		2010	
	(in millions)					
Unrecognized tax benefits at beginning of year	$120		$296		$199	
Tax positions from current periods	13		46		62	
Tax positions increase from prior periods	7		1		62	
Tax positions decrease from prior periods	(56	)	(111	)	(27	)
Reductions due to settlements	(10	)	(112	)	—	
Reductions due to expired statute of limitations	(4	)	—		—	
Balance at end of year	$70		$120		$296	

The tax positions from current periods for 2012 relate primarily to the tax accounting method change for repairs-generation assets. See "Tax Method of Accounting for Repairs" herein for additional information. The decreases in tax positions from prior periods primarily relate to state income tax credits and the 2009 MC Asset Recovery, LLC refund claim. The American Jobs Creation Act of 2004 created a tax deduction for a portion of income attributable to U.S. production activities as defined in

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Section 199 of the Internal Revenue Code (production activities deduction). The reductions due to settlements relate to a settlement with the IRS of the calculation methodology for the production activities deduction.

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

	2012	2011	2010
	(in millions)		
Tax positions impacting the effective tax rate	$5	$69	$217
Tax positions not impacting the effective tax rate	65	51	79
Balance of unrecognized tax benefits	$70	$120	$296

The tax positions impacting the effective tax rate for 2012 primarily relate to state income tax credits. 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:

	2012	2011	2010
	(in millions)		
Interest accrued at beginning of year	$10	$29	$21
Interest reclassified due to settlements	(9)	(24)	—
Interest accrued during the year	—	5	8
Balance at end of year	$1	$10	$29

Southern Company classifies interest on tax uncertainties as interest expense. The interest reclassified due to settlements in 2012 is primarily associated with state income tax credits and a settlement with the IRS related to the calculation methodology for the production activities deduction.

Southern Company did not accrue any penalties on uncertain tax positions.

It is reasonably possible that the amount of the unrecognized tax benefits associated with a majority of Southern Company's unrecognized tax positions will significantly increase or decrease within 12 months. The resolution of the tax accounting method change for repairs-generation assets, as well as the conclusion or settlement of 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 audited and closed all of Southern Company's consolidated federal income tax returns prior to 2009 and has settled its audits of Southern Company's consolidated federal income tax returns for 2009 and 2010, in principle, pending final approval. Additionally, the IRS has audited and closed Southern Company's 2011 consolidated federal income tax return. For tax years 2010 through 2013, Southern Company is a participant in the Compliance Assurance Process of the IRS. The audits for Southern Company's state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2007.

Tax Method of Accounting for Repairs

Southern Company submitted a tax accounting method change related to the deductibility of repair costs associated with its subsidiaries' generation, transmission, and distribution systems effective for the 2009 consolidated federal income tax return in 2010. In August 2011, the IRS issued a revenue procedure, which provides a safe harbor method of accounting that taxpayers may use to determine eligible repair costs for transmission and distribution property. The IRS continues to work with the utility industry in an effort to define eligible repair costs for generation assets in a consistent manner for all utilities. 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. The utility industry anticipates more detailed guidance concerning these regulations. Due to the uncertainty regarding the ultimate resolution of the repair costs for generation assets, an unrecognized tax position has been recorded for the tax accounting method change for repairs-generation assets. The ultimate outcome of this matter cannot be determined at this time; however, it is not expected to materially impact net income.

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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, 2012 and $206 million as of December 31, 2011, which constitute substantially all of the assets of this trust and are reflected in the balance sheets as long-term debt payable. Alabama Power considers that the mechanisms and obligations relating to the preferred securities issued for its benefit, taken together, constitute a full and unconditional guarantee by it of the trust's payment obligations with respect to these securities. At December 31, 2012 and 2011, trust preferred securities of $200 million and $200 million, respectively, were outstanding.

Securities Due Within One Year

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

	2012	2011
	(in millions)	
Senior notes	$2,085	$1,200
Other long-term debt	227	493
Capitalized leases	23	24
Total	$2,335	$1,717

Maturities through 2017 applicable to total long-term debt are as follows: $2.34 billion in 2013; $448 million in 2014; $2.44 billion in 2015; $1.37 billion in 2016; and $1.14 billion in 2017.

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, 2012, Mississippi Power had outstanding bank term loans totaling $175 million. At December 31, 2011, Mississippi Power had outstanding bank term loans totaling $240 million and Georgia Power had outstanding bank term loans totaling $450 million. Such amounts are reflected in the statements of capitalization as amounts due within one year.

During 2012, the traditional operating companies repaid approximately $565 million of floating rate bank notes bearing interest based on one-month LIBOR. In March 2012, Georgia Power paid at maturity a $250 million aggregate principal amount variable rate long-term bank note. In May 2012, Georgia Power repaid a $200 million aggregate principal amount variable rate short-term bank note due June 2012. In March 2012, Mississippi Power paid at maturity a $75 million aggregate principal amount variable rate long-term bank note. In September 2012, Mississippi Power paid at maturity a $40 million aggregate principal amount variable rate long-term bank note.

During 2012, Mississippi Power entered into a 366-day $100 million aggregate principal amount variable rate bank note bearing interest based on one-month LIBOR. The first advance in the amount of $50 million was made in November 2012. Subsequent to December 31, 2012, the second advance in the amount of $50 million was made. The proceeds of this loan were used for working capital and for 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. At December 31, 2012, Mississippi Power was in compliance with its debt limits.

In addition, these bank loans contain cross default provisions that would be triggered if the borrower defaulted on other indebtedness 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. Mississippi Power is currently in compliance with all such covenants.

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Senior Notes

The traditional operating companies issued a total of $4.0 billion of senior notes in 2012. The proceeds of these issuances were used to repay approximately $2.8 billion of long-term indebtedness, to repay short-term indebtedness, and for other general corporate purposes, including the applicable subsidiary's continuous construction program.

At December 31, 2012 and 2011, Southern Company and its subsidiaries had a total of $17.4 billion and $15.9 billion, respectively, of senior notes outstanding. At December 31, 2012 and 2011, Southern Company had a total of $1.3 billion and $1.8 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.

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 $3.4 billion and $3.4 billion of outstanding pollution control revenue bonds at December 31, 2012 and 2011, 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 October 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 Note 1 under "Property, Plant, and Equipment" and "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 August 2012, the Mississippi Business Finance Corporation (MBFC) entered into an agreement to issue up to $42.5 million aggregate principal amount of MBFC Taxable Revenue Bonds, Series 2012A (Mississippi Power Company Project), up to $21.25 million aggregate principal amount of MBFC Taxable Revenue Bonds, Series 2012B (Mississippi Power Company Project), and up to $21.25 million aggregate principal amount of MBFC Taxable Revenue Bonds, Series 2012C (Mississippi Power Company Project) for the benefit of Mississippi Power. During 2012, the MBFC issued $8.97 million aggregate principal amount of MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2012A, $21.25 million aggregate principal amount of MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2012B, and $21.25 million aggregate principal amount of MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2012C 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 2012A 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, 2012 and 2011 and $51.5 million of such obligations related to taxable revenue bonds outstanding at December 31, 2012. Such amounts are reflected in the statements of capitalization as long-term senior notes and debt.

Other Obligations

In March 2012, Mississippi Power received a $150 million interest-bearing refundable deposit from SMEPA to be applied to the sale price for the proposed sale of an undivided interest in the Kemper IGCC. Until the acquisition is closed, the deposit bears interest at Mississippi Power's AFUDC rate adjusted for income taxes, which was 9.967% per annum at December 31, 2012, and is 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

NOTES (continued)
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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.

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, 2012. 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 October 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 Note 1 under "Property, Plant, and Equipment" for additional information.

Bank Credit Arrangements

At December 31, 2012, committed credit arrangements with banks were as follows:

	Expires[(a)]					Executable Term Loans		Due Within One Year	
Company	2013	2014	2016	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	158	350	800	1,308	1,308	56	—	56	102
Georgia Power	—	250	1,500	1,750	1,740	—	—	—	—
Gulf Power	80	195	—	275	275	45	—	45	35
Mississippi Power	135	165	—	300	300	25	40	65	70
Southern Power	—	—	500	500	500	—	—	—	—
Other	50	—	—	50	50	25	—	25	25
Total	$423	$960	$3,800	$5,183	$5,173	$151	$40	$191	$232

(a) No credit arrangements expire in 2015.

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.

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. At December 31, 2012, Southern Company, the traditional operating companies, and Southern Power were each in compliance with their respective debt limit covenants.

In addition, certain credit arrangements contain cross default provisions to other indebtedness that would trigger an event of default if the applicable borrower defaulted on indebtedness or guarantee obligations over a specified threshold. The cross default provisions are restricted only to the indebtedness, including any guarantee obligations, of the company that has such credit arrangements. Southern Company, the traditional operating companies, and Southern Power are currently in compliance with all such covenants.

A portion of the $5.2 billion 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 requiring liquidity support as of December 31, 2012 was approximately $1.8 billion.

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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, 2012:			
Commercial paper	$820	0.3	%
December 31, 2011:			
Commercial paper	$654	0.3	%
Short-term bank debt	200	1.2	%
Total	$854	0.5	%

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

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, 2012 and 2011 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 2012, 2011, and 2010, the traditional operating companies and Southern Power incurred fuel expense of $5.1 billion, $6.3 billion, and $6.7 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 $171 million, $199 million, and $180 million for 2012, 2011, and 2010, respectively.

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Estimated total obligations under these commitments at December 31, 2012 were as follows:

	PPAs Operating Leases	Other
	(in millions)	
2013	$164	$24
2014	200	19
2015	249	11
2016	258	11
2017	263	8
2018 and thereafter	2,369	69
Total	$3,503	$142

Operating Leases

The Southern Company system has operating lease agreements with various terms and expiration dates. Total rent expense was $155 million, $176 million, and $188 million for 2012, 2011, and 2010, 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, 2012, estimated minimum lease payments under operating leases were as follows:

	Minimum Lease Payments		
	Barges & Railcars	Other	Total
	(in millions)		
2013	$71	$42	$113
2014	57	38	95
2015	24	29	53
2016	19	26	45
2017	11	21	32
2018 and thereafter	11	73	84
Total	$193	$229	$422

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 2018 with maximum obligations under these leases of $83 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.

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 2012, Southern Company issued 12.1 million shares of common stock for $397 million through employee and director stock plans. In 2011, Southern Company raised $723 million from the issuance of 21.9 million new common shares through the Southern Investment Plan and employee and director stock plans.

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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. Under this program, approximately 9 million shares have been repurchased through December 31, 2012 at a total cost of $430 million. In January 2013, Southern Company announced that it planned to continue this program through 2015. Pursuant to Board approval, Southern Company may repurchase shares through open market purchases or privately negotiated transactions, in accordance with applicable securities laws.

Shares Reserved

At December 31, 2012, a total of 130 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 130 million shares reserved, there were 39 million shares of common stock remaining available for awards under the Omnibus Incentive Compensation Plan as of December 31, 2012.

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, 2012, there were 6,026 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. For certain stock option awards, a change in control will provide accelerated vesting.

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	2012	2011	2010
Expected volatility	17.7%	17.5%	17.4%
Expected term (in years)	5.0	5.0	5.0
Interest rate	0.9%	2.3%	2.4%
Dividend yield	4.2%	4.8%	5.6%
Weighted average grant-date fair value	$3.39	$3.23	$2.23

Southern Company's activity in the stock option program for 2012 is summarized below:

	Shares Subject to Option	Weighted Average Exercise Price
Outstanding at December 31, 2011	40,956,822	$33.88
Granted	7,153,669	44.50

Exercised	(12,120,419)	32.76
Cancelled	(73,769)	37.75
Outstanding at December 31, 2012	35,916,303	$36.37
Exercisable at December 31, 2012	22,724,015	$34.09

The number of stock options vested, and expected to vest in the future, as of December 31, 2012 was not significantly different from the number of stock options outstanding at December 31, 2012 as stated above. As of December 31, 2012, 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 $243 million and $199 million, respectively.

As of December 31, 2012, there was $8 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, 2012, 2011, and 2010, total compensation cost for stock option awards recognized in income was $23 million, $22 million, and $22 million, respectively, with the related tax benefit also recognized in income of $9 million, $8 million, and $9 million, respectively.

The total intrinsic value of options exercised during the years ended December 31, 2012, 2011, and 2010 was $162 million, $155 million, and $57 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $62 million, $60 million, and $22 million for the years ended December 31, 2012, 2011, and 2010, 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, 2012, 2011, and 2010 was $397 million, $528 million, and $198 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	2012	2011	2010
Expected volatility	16.0%	19.2%	20.7%
Expected term (in years)	3.0	3.0	3.0
Interest rate	0.4%	1.4%	1.4%
Annualized dividend rate	$1.89	$1.82	$1.75
Weighted average grant-date fair value	$41.99	$35.97	$30.13

Total unvested performance share units outstanding as of December 31, 2011 were 1,719,598. During 2012, 842,447 performance share units were granted, 842,710 performance share units were vested, and 86,179 performance share units were forfeited resulting in 1,633,156 unvested units outstanding at December 31, 2012. In January 2013, the vested performance share award units were converted into 1,137,817 shares outstanding at a share price of $43.05 for the three-year performance and vesting period ended December 31, 2012.

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For the years ended December 31, 2012, 2011, and 2010, total compensation cost for performance share units recognized in income was $28 million, $18 million, and $9 million, respectively, with the related tax benefit also recognized in income of $11 million, $7 million, and $4 million, respectively. As of December 31, 2012, there was $33 million of total unrecognized compensation cost related to performance share award units that will be recognized over a weighted-average period of approximately 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		
	2012	2011	2010
	(in millions)		
As reported shares	871	857	832
Effect of options and performance share award units	8	7	5
Diluted shares	879	864	837

Stock options and performance share award units that were not included in the diluted earnings per share calculation because they were anti-dilutive were immaterial as of December 31, 2012 and 2011. Assuming an average stock price of $47.89 and $42.67 (the highest exercise prices of the anti-dilutive options outstanding in 2012 and 2011, respectively), the effect of options and performance share award units would have been immaterial for the years ended December 31, 2012 and 2011.

Common Stock Dividend Restrictions

The income of Southern Company is derived primarily from equity in earnings of its subsidiaries. At December 31, 2012, consolidated retained earnings included $6.4 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 $12.6 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 $117.5 million per incident for each licensed reactor it operates but not more than an aggregate of $17.5 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 $235 million and $232 million, respectively, per incident, but not more than an aggregate of $35 million 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 October 29, 2013. 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 policies that currently provide decontamination, excess property insurance, and premature decommissioning coverage up to $2.25 billion for losses in excess of the $500 million primary coverage. This excess insurance is also provided by NEIL.

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 the maximum limit allowed by NEIL, subject to ownership limitations. Each facility has elected a 12-week deductible waiting period.

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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 if losses each year exceed the accumulated funds available to the insurer under that policy. The current maximum annual assessments for Alabama Power and Georgia Power under the NEIL policies would be $42 million and $70 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.

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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.

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As of December 31, 2011, 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, 2011:	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	$—	$14	$—	$14
Interest rate derivatives	—	13	—	13
Foreign currency derivatives	—	2	—	2
Nuclear decommissioning trusts:[a]				
Domestic equity	396	58	—	454
Foreign equity	124	48	—	172
U.S. Treasury and government agency securities	17	33	—	50
Municipal bonds	—	82	—	82
Corporate bonds	—	260	—	260
Mortgage and asset backed securities	—	151	—	151
Other investments	—	36	—	36
Cash equivalents and restricted cash	1,024	—	—	1,024
Other investments	3	50	14	67
Total	$1,564	$747	$14	$2,325
Liabilities:				
Energy-related derivatives	$—	$245	$—	$245
Interest rate derivatives	—	33	—	33
Foreign currency derivatives	—	3	—	3
Total	$—	$281	$—	$281

(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 LIBOR interest rates. Interest rate and foreign currency 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. Inputs for foreign currency derivatives are from observable market sources. See Note 11 for additional information on how these derivatives are used.

"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 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

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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.

For fair value measurements of investments within the nuclear decommissioning trusts and rabbi trust funds, 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 and rabbi trust funds 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.

As of December 31, 2012 and 2011, 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, 2012:	(in millions)			
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
As of December 31, 2011:				
Nuclear decommissioning trusts:				
Corporate bonds – commingled funds	$32	None	Daily	Not applicable
Equity – commingled funds	48	None	Daily/Monthly	Daily/7 days
Other – commingled funds	25	None	Daily	Not applicable
Trust-owned life insurance	87	None	Daily	15 days
Cash equivalents and restricted cash:				
Money market funds	1,024	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 external trust funds to comply with the NRC's regulations. 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 depository receipts, including American depositary receipts, European depositary receipts and global depository 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.

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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.

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, 2012 and 2011, 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:		
2012	$21,530	$23,480
2011	$20,272	$22,144

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.

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 sales 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.

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, 2012, the net volume of energy-related derivative contracts for natural gas positions for the Southern Company system, together with the longest hedge date over which the respective entity is hedging its exposure to the variability in future cash flows for forecasted transactions and the longest date for derivatives not designated as hedges, were as follows:

	Net Purchased mmBtu* (in millions)	Longest Hedge Date	Longest Non-Hedge Date
Southern Company	276	2017	2017

* million British thermal units

In addition to the volumes discussed in the table 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 6 million mmBtu.

For cash flow hedges, the amounts expected to be reclassified from OCI to revenue and fuel expense for the next 12-month period ending December 31, 2013 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.

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At December 31, 2012, the following interest rate derivatives were outstanding:

	Notional Amount (in millions)	Interest Rate Received	Interest Rate Paid*	Hedge Maturity Date	Fair Value Gain (Loss) December 31, 2012 (in millions)
Fair value hedges of existing debt					
Southern Company	$ 350	4.15%	3-month LIBOR + 1.96% spread	May 2014	$ 10

* Weighted Average

For the year ended December 31, 2012, the Company had realized net losses of $52 million upon termination of certain interest rate derivatives at the same time the related debt was issued. The effective portion of these losses has been deferred in OCI and is being amortized to interest expense over the life of the original interest rate derivative, reflecting the period in which the forecasted hedged transaction affects earnings. The estimated pre-tax losses that will be reclassified from OCI to interest expense for the 12-month period ending December 31, 2013 are $14 million. 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 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, 2012, the fair value of the foreign currency derivative outstanding was immaterial.

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Derivative Financial Statement Presentation and Amounts
At December 31, 2012 and 2011, the fair value of energy-related derivatives, interest rate derivatives, and foreign currency derivatives was reflected in the balance sheets as follows:

Derivative Category	Asset Derivatives Balance Sheet Location	2012	2011	Liability Derivatives Balance Sheet Location	2012	2011
		(in millions)			(in millions)	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	$10	$9	Liabilities from risk management activities	$74	$163
	Other deferred charges and assets	13	5	Other deferred credits and liabilities	35	72
Total derivatives designated as hedging instruments for regulatory purposes		$23	$14		$109	$235
Derivatives designated as hedging instruments in cash flow and fair value hedges						
Energy-related derivatives:	Other current assets	$—	$—	Liabilities from risk management activities	$—	$1
Interest rate derivatives:	Other current assets	7	6	Liabilities from risk management activities	—	33
	Other deferred charges and assets	3	7	Other deferred credits and liabilities	—	—
Foreign currency derivatives:	Other current assets	—	—	Liabilities from risk management activities	—	1
Total derivatives designated as hedging instruments in cash flow and fair value hedges		$10	$13		$—	$35
Derivatives not designated as hedging instruments						
Energy-related derivatives:	Other current assets	$1	$—	Liabilities from risk management activities	$1	$9
	Other deferred charges and assets	2	—	Other deferred credits and liabilities	1	—
Foreign currency derivatives:	Other current assets	—	2	Liabilities from risk management activities	—	2

Total derivatives not designated as hedging instruments	$3	$2	$2	$11
Total	$36	$29	$111	$281

All derivative instruments are measured at fair value. See Note 10 for additional information.

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At December 31, 2012 and 2011, 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	2012	2011	Unrealized Gains Balance Sheet Location	2012	2011
		(in millions)			(in millions)	
Energy-related derivatives:	Other regulatory assets, current	$(74)	$(163)	Other regulatory liabilities, current	$10	$9
	Other regulatory assets, deferred	(35)	(72)	Other regulatory liabilities, deferred	13	5
Total energy-related derivative gains (losses)		$(109)	$(235)		$23	$14

For the years ended December 31, 2012, 2011, and 2010, the pre-tax effects of interest rate and foreign currency derivatives designated as fair value hedging instruments on the statements of income were as follows:

Derivatives in Fair Value Hedging Relationships

Derivative Category	Statements of Income Location	Amount 2012	2011	2010
		(in millions)		
Interest rate derivatives:	Interest expense	$(3)	$3	$10
Foreign currency derivatives:	Other operations and maintenance	1	(4)	3
Total		$(2)	$(1)	$13

For the years ended December 31, 2012, 2011, and 2010, 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; there was no material impact on Southern Company's statements of income.

For the years ended December 31, 2012, 2011, and 2010, 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; therefore, there was no material impact on Southern Company's statements of income.

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For the years ended December 31, 2012, 2011, and 2010, the pre-tax effects of derivatives designated as cash flow hedging instruments on the statements of income were as follows:

Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Recognized in OCI on Derivative (Effective Portion)			Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)			
					Amount		
Derivative Category	2012	2011	2010	Statements of Income Location	2012	2011	2010
	(in millions)				(in millions)		
Energy-related derivatives	$—	$—	$1	Fuel	$—	$—	$—
Interest rate derivatives	(19)	(28)	(3)	Interest expense, net of amounts capitalized	(18)	(14)	(25)
Foreign currency derivatives	—	—	1	Other operations and maintenance	—	—	1
				Other income (expense), net	—	(1)	—
Total	$(19)	$(28)	$(1)		$(18)	$(15)	$(24)

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 substantial 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.

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, 2012, the fair value of derivative liabilities with contingent features was $15 million.

At December 31, 2012, the Company had no collateral posted with its derivative counterparties. The maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $15 million. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. 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.

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12. SEGMENT AND RELATED INFORMATION
Southern Company's reportable business segments are the sale of electricity in the Southeast by the four traditional operating companies and Southern Power. Revenues from sales by Southern Power to the traditional operating companies were $425 million, $359 million, and $371 million in 2012, 2011, and 2010, 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 intersegment revenues are not material.
Financial data for business segments and products and services was as follows:

	Electric Utilities						
	Traditional Operating Companies	Southern Power	Eliminations	Total	All Other	Eliminations	Consolidated
	(in millions)						
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)*	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)*	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
2010							
Operating revenues	$16,712	$1,130	$(468)	$17,374	$162	$(80)	$17,456
Depreciation and amortization	1,376	119	—	1,495	18	—	1,513
Interest income	22	—	—	22	3	(1)	24
Interest expense	757	76	—	833	63	(1)	895
Income taxes	1,039	75	—	1,114	(89)	1	1,026
Segment net income (loss)*	1,860	131	—	1,991	(11)	(5)	1,975
Total assets	51,144	3,438	(128)	54,454	1,178	(600)	55,032
Gross property additions	4,029	405	—	4,434	9	—	4,443

* After dividends on preferred and preference stock of subsidiaries.

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Products and Services
Electric Utilities' Revenues

Year	Retail	Wholesale	Other	Total
	(in millions)			
2012	$14,187	$1,675	$616	$16,478
2011	$15,071	$1,905	$611	$17,587
2010	$14,791	$1,994	$589	$17,374

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13. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)
Summarized quarterly financial information for 2012 and 2011 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	Dividends	Trading Price Range High	Low
	(in millions)						
March 2012	$3,604	$766	$368	$0.42	$0.4725	$46.06	$43.71
June 2012	4,181	1,143	623	0.71	0.4900	48.45	44.22
September 2012	5,049	1,740	976	1.11	0.4900	48.59	44.64
December 2012	3,703	814	383	0.44	0.4900	47.09	41.75
March 2011	$4,012	$854	$422	$0.50	$0.4550	$38.79	$36.51
June 2011	4,521	1,136	604	0.71	0.4725	40.87	37.43
September 2011	5,428	1,652	916	1.07	0.4725	43.09	35.73
December 2011	3,696	589	261	0.30	0.4725	46.69	41.00

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

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	2012	2011	2010	2009	2008
Operating Revenues (in millions)	$16,537	$17,657	$17,456	$15,743	$17,127
Total Assets (in millions)	$63,149	$59,267	$55,032	$52,046	$48,347
Gross Property Additions (in millions)	$5,059	$4,853	$4,443	$4,913	$4,122
Return on Average Common Equity (percent)	13.10	13.04	12.71	11.67	13.57
Cash Dividends Paid Per Share of Common Stock	$1.9425	$1.8725	$1.8025	$1.7325	$1.6625
Consolidated Net Income After Dividends on Preferred and Preference Stock of Subsidiaries (in millions)	$2,350	$2,203	$1,975	$1,643	$1,742
Earnings Per Share —					
Basic	$2.70	$2.57	$2.37	$2.07	$2.26
Diluted	2.67	2.55	2.36	2.06	2.25
Capitalization (in millions):					
Common stock equity	$18,297	$17,578	$16,202	$14,878	$13,276
Preferred and preference stock of subsidiaries	707	707	707	707	707
Redeemable preferred stock of subsidiaries	375	375	375	375	375
Long-term debt	19,274	18,647	18,154	18,131	16,816
Total (excluding amounts due within one year)	$38,653	$37,307	$35,438	$34,091	$31,174
Capitalization Ratios (percent):					
Common stock equity	47.3	47.1	45.7	43.6	42.6
Preferred and preference stock of subsidiaries	1.8	1.9	2.0	2.1	2.3
Redeemable preferred stock of subsidiaries	1.0	1.0	1.1	1.1	1.2
Long-term debt	49.9	50.0	51.2	53.2	53.9
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	$21.09	$20.32	$19.21	$18.15	$17.08
Market price per share:					
High	$48.59	$46.69	$38.62	$37.62	$40.60
Low	41.75	35.73	30.85	26.48	29.82
Close (year-end)	42.81	46.29	38.23	33.32	37.00
Market-to-book ratio (year-end) (percent)	203.0	227.8	199.0	183.6	216.6
Price-earnings ratio (year-end) (times)	15.9	18.0	16.1	16.1	16.4
Dividends paid (in millions)	$1,693	$1,601	$1,496	$1,369	$1,279
Dividend yield (year-end) (percent)	4.5	4.0	4.7	5.2	4.5
Dividend payout ratio (percent)	72.0	72.7	75.7	83.3	73.5

Shares outstanding (in thousands):					
Average	871,388	856,898	832,189	794,795	771,039
Year-end	867,768	865,125	843,340	819,647	777,192
Stockholders of record (year-end)	149,628	155,198	160,426	* 92,799	97,324
Traditional Operating Company Customers (year-end) (in thousands):					
Residential	3,832	3,809	3,813	3,798	3,785
Commercial	580	579	580	580	594
Industrial	15	15	15	15	15
Other	9	9	9	9	8
Total	4,436	4,412	4,417	4,402	4,402
Employees (year-end)	26,439	26,377	25,940	26,112	27,276

* In July 2010, Southern Company changed its transfer agent from Southern Company Services, Inc. to Mellon Investor Services LLC (n/k/a Computershare Shareowner Services, LLC). The change in the number of stockholders of record is primarily attributed to the calculation methodology used by Mellon Investor Services LLC.

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	2012	2011	2010	2009	2008
Operating Revenues (in millions):					
Residential	$5,891	$6,268	$6,319	$5,481	$5,476
Commercial	5,097	5,384	5,252	4,901	5,018
Industrial	3,071	3,287	3,097	2,806	3,445
Other	128	132	123	119	116
Total retail	14,187	15,071	14,791	13,307	14,055
Wholesale	1,675	1,905	1,994	1,802	2,400
Total revenues from sales of electricity	15,862	16,976	16,785	15,109	16,455
Other revenues	675	681	671	634	672
Total	$16,537	$17,657	$17,456	$15,743	$17,127
Kilowatt-Hour Sales (in millions):					
Residential	50,454	53,341	57,798	51,690	52,262
Commercial	53,007	53,855	55,492	53,526	54,427
Industrial	51,674	51,570	49,984	46,422	52,636
Other	919	936	943	953	934
Total retail	156,054	159,702	164,217	152,591	160,259
Wholesale sales	27,563	30,345	32,570	33,503	39,368
Total	183,617	190,047	196,787	186,094	199,627
Average Revenue Per Kilowatt-Hour (cents):					
Residential	11.68	11.75	10.93	10.60	10.48
Commercial	9.62	10.00	9.46	9.16	9.22
Industrial	5.94	6.37	6.20	6.04	6.54
Total retail	9.09	9.44	9.01	8.72	8.77
Wholesale	6.08	6.28	6.12	5.38	6.10
Total sales	8.64	8.93	8.53	8.12	8.24
Average Annual Kilowatt-Hour Use Per Residential Customer	13,187	13,997	15,176	13,607	13,844
Average Annual Revenue Per Residential Customer	$1,540	$1,645	$1,659	$1,443	$1,451
Plant Nameplate Capacity Ratings (year-end) (megawatts)	45,740	43,555	42,961	42,932	42,607
Maximum Peak-Hour Demand (megawatts):					
Winter	31,705	34,617	35,593	33,519	32,604
Summer	35,479	36,956	36,321	34,471	37,166
System Reserve Margin (at peak) (percent)	20.8	19.2	23.3	26.4	15.3
Annual Load Factor (percent)	59.5	59.0	62.2	60.6	58.7
Plant Availability (percent)*:					
Fossil-steam	89.4	88.1	91.4	91.3	90.5
Nuclear	94.2	93.0	92.1	90.1	91.3
Source of Energy Supply (percent):					

Coal	35.2	48.7	55.0	54.7	64.0
Nuclear	16.2	15.0	14.1	14.9	14.0
Hydro	1.7	2.1	2.5	3.9	1.4
Oil and gas	38.3	28.0	23.7	22.5	15.4
Purchased power	8.6	6.2	4.7	4.0	5.2
Total	100.0	100.0	100.0	100.0	100.0

* Beginning in 2012, plant availability is calculated as a weighted equivalent availability.

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ALABAMA POWER COMPANY
FINANCIAL SECTION

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Alabama Power Company 2012 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 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, 2012.

/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, 2013

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, 2012 and 2011, 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, 2012. 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-148 to II-196) present fairly, in all material respects, the financial position of Alabama Power Company as of December 31, 2012 and 2011, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP
Birmingham, Alabama
February 27, 2013

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Alabama Power Company 2012 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, 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 2012 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 2012 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 2012 results compared to its targets for some of these key indicators are reflected in the following chart:

Key Performance Indicator	2012 Target Performance	2012 Actual Performance
Customer Satisfaction	Top quartile in customer surveys	Top quartile
Peak Season EFOR — fossil/hydro	4.99% or less	0.75%
Net Income After Dividends on Preferred and Preference Stock	$701 million	$704 million

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance. The performance achieved in 2012 reflects the continued emphasis that management places on these indicators, as well as the commitment shown by employees in achieving or exceeding management's expectations.
Earnings
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.

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Alabama Power Company 2012 Annual Report

The Company's 2011 net income after dividends on preferred and preference stock of $708 million increased $1 million (0.1%) from the prior year. The increase was due to a reduction in other operations and maintenance expenses, an increase in revenues under rate certificated new plant environmental (Rate CNP Environmental) associated with the completion of construction projects related to environmental mandates, and an increase in industrial kilowatt-hour (KWH) sales. The factors increasing net income were partially offset by reductions in wholesale revenues from sales to non-affiliates, decreases in weather-related revenues due to closer to normal weather in 2011 compared to 2010, and a reduction in allowance for funds used during construction (AFUDC) equity.

RESULTS OF OPERATIONS

A condensed income statement for the Company follows:

	Amount	Increase (Decrease) from Prior Year	
	2012	2012	2011
	(in millions)		
Operating revenues	$5,520	$(182)	$(274)
Fuel	1,503	(176)	(172)
Purchased power	255	(16)	(9)
Other operations and maintenance	1,287	25	(156)
Depreciation and amortization	639	2	31
Taxes other than income taxes	340	1	7
Total operating expenses	4,024	(164)	(299)
Operating income	1,496	(18)	25
Allowance for equity funds used during construction	19	(3)	(14)
Interest income	16	(2)	1
Interest expense, net of amounts capitalized	287	(12)	(4)
Other income (expense), net	(24)	6	—
Income taxes	477	(1)	15
Net income	743	(4)	1
Dividends on preferred and preference stock	39	—	—
Net income after dividends on preferred and preference stock	$704	$(4)	$1

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Alabama Power Company 2012 Annual Report

Operating Revenues
Operating revenues for 2012 were $5.5 billion, reflecting a $182 million decrease from 2011. Details of operating revenues were as follows:

	Amount 2012	2011
	(in millions)	
Retail — prior year	$4,972	$5,076
Estimated change in —		
Rates and pricing	69	88
Sales growth (decline)	61	42
Weather	(115)	(147)
Fuel and other cost recovery	(54)	(87)
Retail — current year	4,933	4,972
Wholesale revenues —		
Non-affiliates	277	287
Affiliates	111	244
Total wholesale revenues	388	531
Other operating revenues	199	199
Total operating revenues	$5,520	$5,702
Percent change	(3.2)%	(4.6)%

Retail revenues in 2012 were $4.9 billion. These revenues decreased $39 million (0.8%) in 2012 and decreased $104 million (2.0%) in 2011, each as compared to the prior year. The decrease in 2012 was due to milder weather, a reduction in revenues under Rate CNP Environmental, and a reduction in fuel revenues when compared to 2011. The decreases were 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. The decrease in 2011 was due to closer to normal weather in 2011 compared to 2010 and a reduction in fuel revenues. The decreases were partially offset by increased revenues associated with Rate CNP Environmental for the completion of construction projects related to environmental mandates and the elimination of a tax-related adjustment under the Company's rate structure. 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 – Energy Cost Recovery" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Energy Cost Recovery" for additional information.

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

	2012	2011	2010
	(in millions)		
Unit power sales —			
Capacity	$—	$—	$84
Energy	—	6	95
Total	—	6	179
Other power sales —			
Capacity and other	143	148	148
Energy	134	133	138

Total	277	281	286
Total non-affiliated	$277	$287	$465

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Alabama Power Company 2012 Annual Report

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 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. The price of energy decreased 5.2%, partially offset by a 1.8% increase in KWH sales. In 2011, wholesale revenues from sales to non-affiliates decreased $178 million (38.3%) reflecting a $94 million decrease in revenue from energy sales and an $84 million decrease in capacity revenues. These decreases were primarily due to the expiration of long-term unit power sales contracts in 2010. KWH sales decreased 46.9%, partially offset by a 15.3% increase in the price of energy. 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. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Retail Rate Adjustments" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Rate RSE" for additional information.

Wholesale revenues from sales to affiliated companies will vary from year to year depending on demand and the availability and cost of generating resources at each company. These affiliated 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 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. KWH sales decreased 45% and there was a 17.6% decrease in the price of energy. In 2011, wholesale revenues from sales to affiliates increased $8 million (3.4%). The change from prior year revenues was not material.

In 2012 and 2011, other operating revenues were $199 million. In 2011, the change 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 2012 and the percent change by year were as follows:

	Total KWHs 2012 (in billions)	Total KWH Percent Change 2012		Total KWH Percent Change 2011		Weather-Adjusted Percent Change 2012		Weather-Adjusted Percent Change 2011	
Residential	17.6	(5.6	)%	(8.7	)%	2.6	%	0.6	%
Commercial	14.0	(1.5	)	(3.7	)	0.6		(0.6	)
Industrial	22.1	2.3		5.1		2.3		5.1	
Other	0.2	—		(0.9	)	—		(0.9	)
Total retail	53.9	(1.4	)	(2.3	)	1.9	%	2.0	%
Wholesale —									
Non-affiliates	4.6	0.6		(46.9	)				
Affiliates	3.9	(44.9	)	15.3					
Total wholesale	8.5	(26.9	)	(21.3	)				
Total energy sales	62.4	(5.9	)%	(6.2	)%				

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 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.

Retail energy sales in 2011 were 2.3% less than in 2010. Residential and commercial sales decreased 8.7% and 3.7%, respectively, due primarily to closer to normal weather in 2011 compared to 2010. Industrial sales increased 5.1% in 2011 as a result of increased customer demand, primarily in the primary metals and chemicals sectors, due to a recovering economy.

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.

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

	2012	2011	2010
Total generation (billions of KWHs)	59.9	64.8	69.2
Total purchased power (billions of KWHs)	5.4	4.7	5.0
Sources of generation (percent) —			
Coal	53	56	61
Nuclear	25	22	19
Gas	18	17	15
Hydro	4	5	5
Cost of fuel, generated (cents per net KWH) —			
Coal	3.30	3.16	3.02
Nuclear	0.80	0.66	0.60
Gas	3.06	3.92	4.47
Average cost of fuel, generated (cents per net KWH)*	2.61	2.70	2.76
Average cost of purchased power (cents per net KWH)**	4.86	6.04	6.42

* 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 $1.8 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 expenses were $2.0 billion in 2011, a decrease of $181 million (8.5%) compared to 2010. The decrease was primarily due to a $108 million decrease related to lower KWHs generated as a result of closer to normal weather in 2011 compared to 2010, a reduction in unit power energy sales, and a $56 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 – Energy Cost Recovery" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Energy Cost Recovery" for additional information.

From an overall global market perspective, coal prices decreased from levels experienced in 2011 due to lower demand. In the U.S., this decrease was due primarily to relatively lower domestic natural gas prices that contributed to displacement of coal generation by natural gas-fueled generating units. Lower domestic natural gas prices in 2012 were driven by continued robust supplies, including production from shale gas, and only modest increases in overall U.S. consumption.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Alabama Power Company 2012 Annual Report

Uranium prices began to decrease during the second half of 2012 as extended reactor shutdowns in Europe and Asia caused global demand for uranium to drop below the level of previous years, while production increased. Changes in the cost of fuel for nuclear generation tend to lag behind changes in uranium market prices. Even though uranium prices decreased slightly during 2012, the cost of fuel for nuclear generation increased in 2012, reflecting the higher uranium prices from previous years when the uranium was purchased.

Fuel

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. Fuel expenses were $1.7 billion in 2011, a decrease of $172 million (9.3%) compared to 2010. This decrease was primarily due to a 13.1% decrease in KWHs generated by coal and a 12.4% decrease in the average cost of KWHs generated by natural gas, which excludes fuel associated with tolling agreements, partially offset by a 10.7% increase in the average cost of KWHs generated by nuclear.

Purchased Power - Non-Affiliates

In 2012 and 2011, purchased power from non-affiliates was $73 million. In 2011, purchased power from non-affiliates increased $1 million. The increase over prior year costs was not material.

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 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. Purchased power from affiliates was $198 million in 2011, a decrease of $10 million (4.8%) compared to 2010. This decrease was primarily due to an 18.9% decrease in the average cost per KWH, partially offset by a 6.9% 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 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.

In 2011, other operations and maintenance expenses decreased $156 million (11.0%) as compared to the prior year. Transmission and distribution expenses decreased $79 million primarily related to vegetation management, reliability projects, and a reduction in accruals to the NDR. Nuclear production expenses decreased $33 million primarily related to the change in the nuclear maintenance outage accounting process in 2010 which resulted in no nuclear maintenance outage expenses being recognized in 2011, reducing nuclear production expense by approximately $50 million compared to the prior year. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Nuclear Outage Accounting Order" herein for additional information. The decrease in nuclear production expenses was partially offset by an increase in operations costs related to labor expense. Administrative and general expenses decreased $28 million primarily related to injuries and damages expenses, affiliated service companies' expenses, and property insurance. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Natural Disaster Reserve" herein for additional information.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Alabama Power Company 2012 Annual Report

Depreciation and Amortization
Depreciation and amortization increased $2 million (0.3%) in 2012 and $31 million (5.1%) in 2011, each as compared to the prior year. The increase in 2012 was not material. The increase in 2011 was primarily due to additions to property, plant, and equipment related to environmental mandates (which are offset by revenues associated with Rate CNP Environmental) and transmission and distribution projects. See Note 3 to financial statements under "Retail Regulatory Matters – Rate CNP" for additional information.
In 2011, the Company submitted a depreciation study to FERC and received authorization to use the recommended rates beginning in January 2012.
Taxes Other Than Income Taxes
Taxes other than income taxes increased $1 million (0.3%) in 2012 and $7 million (2.1%) in 2011, each as compared to the prior year. The increase in 2012 was not material. The increase in 2011 was primarily due to increases in state and municipal public utility license tax bases and an increase in local use tax.
Allowance for Funds Used During Construction Equity
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. AFUDC equity decreased $14 million (38.9%) in 2011 as compared to the prior year primarily due to the completion of construction projects related to environmental mandates at Plants Barry, Gaston, and Miller. 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 $12 million (4.0%) in 2012 and $4 million (1.3%) in 2011, each as compared to the prior year. The decrease in 2012 was primarily due to a decrease in interest on long term debt. The decrease in 2011 was not material.
Other Income (Expense), Net
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. Other income (expense), net remained flat in 2011 as compared to the prior year.
Income Taxes
Income taxes decreased $1 million (0.2%) in 2012 and increased $15 million (3.2%) in 2011, each as compared to the prior year. The decrease in 2012 was not material. The increase in 2011 was primarily due to higher pre-tax income, an increase in the tax expense associated with a decrease in AFUDC equity, and prior year tax return actualization.
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.

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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 neighboring 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 economic conditions impact sales for the Company, and 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

In 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including the Company, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. The EPA alleged NSR violations at five coal-fired generating facilities operated by the Company and three coal-fired generating facilities operated by Georgia Power Company (Georgia Power). The civil action sought penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. The case against Georgia Power was administratively closed in 2001 and has not been reopened. After the Company was dismissed from the original action, the EPA filed a separate action in 2001 against the Company in the U.S. District Court for the Northern District of Alabama.

In 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree, resolving claims relating to the alleged NSR violations at Plant Miller. In 2010, the EPA dismissed five of its eight remaining claims against the Company, leaving only three claims, including one relating to a unit co-owned by Mississippi Power Company (Mississippi Power). In March 2011, the U.S. District Court for the Northern District of Alabama granted the Company summary judgment on all remaining claims and dismissed the case with prejudice. That judgment is on appeal to the U.S. Court of Appeals for the Eleventh Circuit. On February 23, 2012, the EPA filed a motion in the U.S. District Court for the Northern District of Alabama seeking vacatur of the judgment and recusal of the judge in the case involving the Company.

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.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Alabama Power Company 2012 Annual Report

Climate Change Litigation
Kivalina Case
In 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs allege that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that some of the defendants (including Southern Company) acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. In 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case. On September 21, 2012, the U.S. Court of Appeals for the Ninth Circuit upheld the U.S. District Court for the Northern District of California's dismissal of the case. On November 27, 2012, the U.S. Court of Appeals for the Ninth Circuit denied the plaintiffs' request for review of the decision. On February 25, 2013, the plaintiffs filed a petition for writ of certiorari with the U.S. Supreme Court. Southern Company believes that these claims are without merit. The ultimate outcome of this matter cannot be determined at this time.
Hurricane Katrina Case
In 2005, immediately following Hurricane Katrina, a lawsuit was filed in the U.S. District Court for the Southern District of Mississippi by Ned Comer on behalf of Mississippi residents seeking recovery for property damage and personal injuries caused by Hurricane Katrina. In 2006, the plaintiffs amended the complaint to include Southern Company and many other electric utilities, oil companies, chemical companies, and coal producers. The plaintiffs allege that the defendants contributed to climate change, which contributed to the intensity of Hurricane Katrina. In 2007, the U.S. District Court for the Southern District of Mississippi dismissed the case. On appeal to the U.S. Court of Appeals for the Fifth Circuit, a three-judge panel reversed the U.S. District Court for the Southern District of Mississippi, holding that the case could proceed, but, on rehearing, the full U.S. Court of Appeals for the Fifth Circuit dismissed the plaintiffs' appeal, resulting in reinstatement of the decision of the U.S. District Court for the Southern District of Mississippi in favor of the defendants. In May 2011, the plaintiffs filed an amended version of their class action complaint, arguing that the earlier dismissal was on procedural grounds and under Mississippi law the plaintiffs have a right to re-file. The amended complaint was also filed against numerous chemical, coal, oil, and utility companies, including the Company. On March 20, 2012, the U.S. District Court for the Southern District of Mississippi dismissed the plaintiffs' amended complaint. On April 16, 2012, the plaintiffs appealed the case to the U.S. Court of Appeals for the Fifth Circuit. The Company believes that these claims are without merit. 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 2012, the Company had invested approximately $3.0 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $62 million, $34 million, and $130 million for 2012, 2011, and 2010, respectively. The Company expects that base level capital expenditures to comply with existing statutes and regulations, including capital expenditures and compliance costs associated with the EPA's final Mercury and Air Toxics Standards (MATS) rule, will be a total of approximately $1.0 billion from 2013 through 2015, with annual

totals of approximately $195 million, $424 million, and $411 million for 2013, 2014, and 2015, respectively.

The Company continues to monitor the development of the EPA's proposed water and coal combustion byproducts 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 byproducts rules for 2013 through 2015. The ultimate capital expenditures and compliance costs with respect to these proposed rules, including additional expenditures required after 2015, 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 Byproducts" herein for additional information.

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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). The impact of SEGCO's ultimate compliance strategy on such PPA costs cannot be determined at this time; however, if such 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 byproducts, 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.

The EPA regulates ground level ozone concentrations through implementation of an eight-hour ozone air quality standard. In 2008, the EPA adopted a more stringent eight-hour ozone National Ambient Air Quality Standard, which it began to implement in September 2011. On May 21, 2012, the EPA published its final determination of nonattainment areas based on the 2008 eight-hour ozone air quality standards. No areas within the Company's service territory were determined to be in nonattainment 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 National Ambient Air Quality Standards and, in January 2013, the EPA officially redesignated the Birmingham area as attainment under both the annual and 24-hour 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 National Ambient Air Quality Standard for sulfur dioxide (SO_2), including the establishment of a new one-hour standard, became effective in 2010. The EPA plans to issue area designations under this new standard in June 2013, and areas within the Company's service territory could ultimately be designated as nonattainment. Implementation of the revised SO_2 standard could require additional reductions in SO_2 emissions and increased compliance and operational costs.

Revisions to the National Ambient Air Quality Standard for nitrogen dioxide (NO_2), which established a new one-hour standard, became effective in 2010. On February 29, 2012, the new NO_2 standard became effective. The EPA designated the entire country as "unclassifiable/attainment" under the new standard, with no nonattainment areas designated. However, the new NO_2 standard could result in significant additional compliance and operational costs

for units that require new source permitting.
In 2008, the EPA approved a revision to Alabama's State Implementation Plan (SIP) requirements related to opacity, which granted some flexibility to affected sources while requiring compliance with Alabama's stringent opacity limits through use of continuous opacity monitoring system data. In April 2011, the EPA attempted to rescind its previous approval of the Alabama SIP revision. This decision impacts facilities operated by the Company, including units co-owned by Mississippi Power. The Company filed an appeal of that decision with the U.S. Court of Appeals for the Eleventh Circuit. The EPA's rescission has affected unit availability and increased maintenance and compliance costs. Unless the court resolves the Company's appeal in its favor, the EPA's rescission will continue to affect the Company's operations.

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 August 2011, the EPA adopted the Cross State Air Pollution Rule (CSAPR) to replace CAIR effective January 1, 2012. However, in December 2011, the U. S. Court of Appeals for the District of Columbia Circuit stayed the rule and, on August 21, 2012, vacated CSAPR in its entirety and directed the EPA to continue to administer CAIR pending the EPA's development of a valid replacement. On January 24, 2013, the U.S. Court of Appeals for the District of Columbia Circuit denied requests by the EPA and other parties for rehearing.

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 (BART) 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 2005, the EPA determined that compliance with CAIR satisfies BART obligations under CAVR, but, on June 7, 2012, the EPA issued a final rule replacing CAIR with CSAPR as an alternative means of satisfying BART obligations. The vacatur of CSAPR creates additional uncertainty with respect to whether additional controls may be required for CAVR and BART compliance.

On February 16, 2012, the EPA published the final 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, unless a one-year compliance extension is granted by the state or local air permitting agency.

Numerous petitions for administrative reconsideration of the MATS rule, including a petition by the Company, have been filed with the EPA. On November 30, 2012, the EPA proposed a reconsideration of certain new source and startup/shutdown issues. The EPA plans to complete its reconsideration rulemaking by March 2013. Challenges to the final rule have also been filed in the U.S. District Court for the District of Columbia by numerous states, environmental organizations, industry groups, and others.

On August 29, 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. If finalized as proposed, this new requirement could result in significant additional compliance and operational costs.

The Company has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the existing and new 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, SO_2 and NO_2 standards, 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.

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Water Quality
In April 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 has entered into an amended settlement agreement to extend the deadline for issuing a final rule until June 27, 2013. If finalized as proposed, some of the Company's facilities may be subject to 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. The ultimate outcome of this rulemaking will depend on the final rule and the outcome of any legal challenges and cannot be determined at this time.
The EPA has announced its determination that revision of the current effluent guidelines for steam electric power plants is warranted and has stated that it intends to propose such revisions by April 2013 and finalize the revisions by May 2014. New advanced wastewater treatment requirements are expected and may result in the installation of additional controls on certain of the Company's facilities, which could result in significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. The impact of the revised guidelines will depend on the specific technology requirements of the final rule and, therefore, cannot be determined at this time. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" for additional information regarding estimated compliance costs for 2013 through 2015.
Coal Combustion Byproducts
The Company currently operates six electric generating plants with on-site coal combustion byproducts storage facilities. In addition to on-site storage, the Company also sells a portion of its coal combustion byproducts to third parties for beneficial reuse. Historically, individual states have regulated coal combustion byproducts and the State of Alabama has its own regulatory parameters. 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 byproducts, 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 byproducts: 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 byproducts 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 byproducts.
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 byproducts could have a material impact on the generation, management, beneficial use, and disposal of such byproducts. 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. See FINANCIAL CONDITION AND

LIQUIDITY – "Capital Requirements and Contractual Obligations" for additional information regarding estimated compliance costs for 2013 through 2015.

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. 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.

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On April 13, 2012, the EPA published proposed regulations to establish standards of performance for greenhouse gas emissions from new fossil fuel steam electric generating units. The EPA has also announced plans to develop federal guidelines for states to establish greenhouse gas emissions performance standards for existing sources. The impact of this rulemaking will depend on the scope and specific requirements of the final rule and the outcome of any legal challenges and, therefore, cannot be determined at this time.

Although the outcome of federal, state, and international initiatives 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 a significant number 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 reported 2011 greenhouse gas emissions of approximately 42 million metric tons of carbon dioxide equivalent. The preliminary estimate of the Company's 2012 greenhouse gas emissions on the same basis is approximately 38 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, which is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units.

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. Though the Coosa application remains pending before FERC, in 2010, the FERC issued a new 30 year license to the Company 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. On November 15, 2012, the FERC denied the Smith Lake Improvement and Stakeholders' Association's request for rehearing. On December 17, 2012, the Smith Lake Improvement and Stakeholders' Association filed for rehearing of the November 15, 2012 order and on January 16, 2013, the FERC denied the request.

In 2006, the Company initiated the process of developing an application to relicense the Martin Dam Project located on the Tallapoosa River. The current Martin license will expire on June 8, 2013. In June 2011, the Company filed an application with the FERC to relicense the Martin Dam Project.

In 2010, the Company initiated the process of developing an application to relicense the Holt Hydroelectric Project located on the Warrior River. The current Holt license will expire on August 31, 2015, and the application for a new license is expected to be filed no later than August 31, 2013.

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 July 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 April 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%. Retail rates remain unchanged when the retail return on common equity (ROE) is projected to be between 13.0% and 14.5%. If the Company's actual retail ROE 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 ROE fall below the allowed equity return range.

In 2011 and 2012, retail rates under Rate RSE remained unchanged from 2010. On November 30, 2012, the Company made its Rate RSE submission to the Alabama PSC of projected data for calendar year 2013; projected earnings were within the specified return range, and, therefore, retail rates under Rate RSE remained unchanged for 2013. Under the terms of Rate RSE, the maximum possible increase for 2014 is 5.00%. However, the Company is working with the Alabama PSC to develop a plan that will potentially preclude the need for a Rate RSE increase in 2014. The ultimate outcome of this matter cannot be determined at this time.

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). Effective April 2011, Rate CNP PPA was reduced by approximately $5 million annually. On March 6, 2012, 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, 2012 through March 31, 2013. It is anticipated that no adjustment will be made to Rate CNP PPA in 2013. As of December 31, 2012, the Company had an under recovered certificated PPA balance of $9 million, $7 million of which is included in deferred under recovered regulatory clause revenues and $2 million of which is included in under recovered regulatory clause revenues in the balance sheet.

On September 17, 2012, the Alabama PSC approved and certificated a PPA for the purchase of approximately 200 megawatts (MWs) of the approximately 400 MWs of energy from wind-powered generating facilities and all associated environmental attributes, including renewable energy credits. The terms of this PPA and a previously approved and certificated PPA 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, to third parties. Approximately 200 MWs of energy from wind-powered generating facilities was operational in December 2012.

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 to recover environmental costs in 2011 or 2012. On November 26, 2012, 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 less than $1 million, which is to be recovered in the billing months of January 2013 through December 2013. On December 4, 2012, the Alabama PSC issued a consent order that the Company leave in effect for 2013 the factors associated with the Company's environmental compliance costs for the year 2012. Any unrecovered amounts associated with 2013 will be reflected in the 2014 filing. As of December 31, 2012, the Company had an under recovered environmental clause balance of $21 million which is included in under recovered regulatory clause revenues in the balance sheet.

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Environmental Accounting Order

Proposed and final environmental regulations could result in significant additional compliance costs that could affect future unit retirement and replacement decisions. In September 2011, the Alabama PSC approved an order allowing for the establishment of a regulatory asset to record the unrecovered investment costs associated with any such decisions, including the unrecovered plant asset balance and the unrecovered costs associated with site removal and closure. 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

On November 6, 2012, the Alabama PSC approved an accounting order for certain compliance-related operation and maintenance expenditures for the years 2013 through 2017, as well as the incremental increase in operation expense related to pension cost for 2013. Under the accounting order, expenses from January 2013 through December 2017 related to compliance with standards addressing Critical Infrastructure Protection issued by the North American Electric Reliability Corporation and cyber security requirements issued by the Nuclear Regulatory Commission (NRC) will be deferred to a regulatory asset account and amortized over a three-year period beginning in January 2015. Expenses from January 2013 through December 2017 related to compliance with NRC guidance addressing the readiness at nuclear facilities within the U.S., as prompted by the earthquake and tsunami that struck Japan in March 2011, also will be deferred as a regulatory asset and recovered over the same amortization period. The compliance-related expenses to be afforded regulatory asset treatment over the five-year period are currently estimated to be approximately $43 million. See "Other Matters" herein for information regarding the NRC's guidance issued as a result of the earthquake and tsunami that struck Japan in 2011. In addition, the accounting order authorizes the Company to defer an incremental increase in its pension cost for 2013. That increased pension cost is estimated to be approximately $17 million. During 2013, the actual incremental increase will be deferred to a regulatory asset account and will be amortized over a three-year period beginning in January 2015. Pursuant to the accounting order, the Company has the ability to accelerate the amortization of the regulatory assets.

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 4, 2012, the Alabama PSC issued a consent order that the Company leave in effect the energy cost recovery rates which began in April 2011 for 2013. Therefore, the Rate ECR factor as of January 1, 2013 remained at 2.681 cents per KWH. Effective with billings beginning in January 2014, the Rate ECR factor will be 5.910 cents per KWH, absent a further order from the Alabama PSC.

As of December 31, 2012 and 2011, the Company had under recovered fuel balances of approximately $4 million and $31 million, respectively, which are included in deferred under recovered regulatory clause revenues in the balance sheets. This classification is 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.

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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.
During the first half of 2011, multiple storms caused varying degrees of damage to the Company's transmission and distribution facilities. The most significant storms occurred in April 2011, causing over 400,000 of the Company's 1.4 million customers to be without electrical service. The cost of repairing the damage to facilities and restoring electrical service to customers as a result of these storms was $42 million for operations and maintenance expenses and $161 million for capital-related expenditures.
In accordance with the order that was issued by the Alabama PSC in July 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, 2012 and December 31, 2011 were approximately $103 million and $110 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 2010, the Alabama PSC approved a change to the nuclear maintenance outage accounting process associated with routine refueling activities. Previously, the Company accrued nuclear outage operations and maintenance expenses for the two units at Plant Farley during the 18-month cycle for the outages. In accordance with the 2010 order, nuclear outage expenses are deferred when the charges actually occur and then amortized over the subsequent 18-month period.
The initial result of implementation of the accounting order was that no nuclear maintenance outage expenses were recognized from January 2011 through December 2011, which decreased nuclear outage operations and maintenance expenses in 2011 from 2010 by approximately $50 million. During the fall of 2011, approximately $38 million of actual nuclear outage expenses associated with one unit at Plant Farley was deferred to a regulatory asset account; beginning in January 2012, these deferred costs are being amortized to nuclear operations and maintenance expenses over an 18-month period. During the spring of 2012, approximately $31 million of actual nuclear outage expenses

associated with the second unit at Plant Farley was deferred to a regulatory asset account; beginning in July 2012, these deferred costs are being amortized to nuclear operations and maintenance expenses 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 existing order.

Income Tax Matters

Bonus Depreciation

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 to be placed in service in 2013), which will have a positive impact on the future cash flows of the Company through 2013.

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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 to be 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 will have a positive impact on the future cash flows of the Company through 2014.
Consequently, the Company's positive cash flow benefit is estimated to be between $110 million and $120 million in 2013.

Other Matters

In accordance with accounting standards related to employers' accounting for pensions, the Company recorded pension costs of $6 million in 2012 and recorded non-cash pre-tax pension income of $21 million and $19 million in 2011 and 2010, respectively. Postretirement benefit costs for the Company were $10 million, $11 million, and $14 million in 2012, 2011, and 2010, 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 byproducts, 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 March 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. On March 12, 2012, the NRC issued three orders and a request for information based on the July 2011 NRC task force report recommendations that included, among other items, additional mitigation strategies for beyond-design-basis events, enhanced spent fuel pool instrumentation capabilities, hardened vents for certain classes of containment structures, site specific evaluations for seismic and flooding hazards, and various plant evaluations to ensure adequate coping capabilities during station blackout and other conditions. On August 29, 2012, the NRC staff issued the final interim staff guidance document, which offers acceptable approaches to meeting the requirements of the NRC's orders before the December 31, 2016 compliance deadline. The interim staff guidance is not mandatory, but licensees would be required to obtain NRC approval for taking an approach other than as outlined in the interim staff guidance. 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.

See RISK FACTORS of the Company in Item 1A of the Form 10-K for a discussion of 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.

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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, nuclear decommissioning, 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, income tax, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. The Company periodically evaluates its exposure to such risks and, in accordance with GAAP, records reserves for those matters where a non-tax-related loss is considered probable and reasonably estimable and records a tax asset or liability if it is more likely than not that a tax position will be sustained. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect the Company's 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 $7 million or less change in total annual benefit expense and a $96 million or less change in projected obligations.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2012. 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 2013 through 2015, 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 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, 2012 as compared to December 31, 2011. No contributions to the qualified pension plan were made for the year ended December 31, 2012. 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 2013.

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 provided from operating activities in 2011 totaled $2.1 billion, an increase of $675 million as compared to 2010. The increase in cash provided from operating activities was primarily due to accrued taxes and deferred income taxes related to benefits associated with bonus depreciation, other current liabilities, accounts payable, and depreciation and amortization.

Net cash used for investing activities totaled $0.9 billion for 2012 and $1.0 billion for 2011 and 2010, primarily due to gross property additions to utility plant of $0.9 billion, $1.0 billion, and $0.9 billion for 2012, 2011, and 2010, respectively. 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 $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. Net cash used for financing activities totaled $600 million in 2010 primarily due to the payment of 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 2012 include increases of $297 million in long-term debt, $269 million in property, plant, and equipment associated with routine property additions, $147 million in accumulated deferred income taxes related to bonus depreciation, $89 million in other regulatory assets, deferred, and $131 million in fossil fuel stock, at average cost, partially offset by decreases of $250 million of securities due within one year and $207 million in cash and cash equivalents.

The Company's ratio of common equity to total capitalization, including short-term debt, was 44.0% in 2012 and 43.9% in 2011. 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 Securities and Exchange Commission (SEC) under the Securities Act of 1933, as amended. The amounts of securities authorized by the Alabama PSC are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

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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, 2012, the Company had approximately $137 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2012 were as follows:

Expires[a]					Executable Term-Loans		Due Within One Year	
2013	2014	2016	Total	Unused	One Year	Two Years	Term Out	Not Term Out
			(in millions)					
$158	$350	$800	$1,308	$1,308	$56	$—	$56	$102

(a) No credit arrangements expire in 2015.

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 that are restricted only to the indebtedness (including guarantee obligations) of the Company. The Company is currently in compliance with all such covenants. 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. These credit arrangements provide liquidity support to the Company's variable rate pollution control revenue bonds and commercial paper borrowings. As of December 31, 2012, the Company had $793 million of outstanding pollution control revenue bonds requiring liquidity support.

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, 2012:					
Commercial paper	$—	—%	$6	0.2%	$57
December 31, 2011:					
Commercial paper	$—	—%	$20	0.2%	$255
December 31, 2010:					
Commercial paper	$—	—%	$7	0.2%	$135

(a) Average and maximum amounts are based upon daily balances during the twelve-month periods ended December 31, 2012, 2011, and 2010.

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

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Financing Activities

In January 2012, the Company issued $250 million aggregate principal amount of Series 2012A 4.10% Senior Notes due January 15, 2042. The proceeds were used for general corporate purposes, including the Company's continuous construction program. The Company settled $100 million of interest rate swaps related to this issuance at a cost of $1 million. The cost is being amortized to interest expense, in earnings, over 10 years.

In March 2012, the Company redeemed approximately $1 million aggregate principal amount of The Industrial Development Board of the Town of West Jefferson Solid Waste Disposal Revenue Bonds (Alabama Power Company Miller Plant Project), Series 2008.

In April 2012, the Company redeemed $250 million aggregate principal amount of its Series 2007B 5.875% Senior Notes due April 1, 2047.

In October 2012, the Company issued $400 million aggregate principal amount of Series 2012B 0.550% Senior Notes due October 15, 2015. The proceeds were used to redeem $200 million aggregate principal amount of Series 2007C 6.00% Senior Insured Monthly Notes due October 15, 2037, and for general corporate purposes, including the Company's continuous construction program.

In December 2012, the Company issued $350 million aggregate principal amount of Series 2012C 3.85% Senior Notes due December 1, 2042. The proceeds, together with other funds of the Company, were used to pay, at maturity, $500 million aggregate amount of the Company's Series 2007D 4.85% Senior Notes due December 15, 2012. The Company settled $300 million of interest rate swaps related to the issuance of the Series 2012C Senior Notes at a cost of $35 million. The cost is being amortized to interest expense, in earnings, over 10 years.

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, 2012, the maximum potential collateral requirements under these contracts at a rating below BBB- and/or Baa3 were approximately $273 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.

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, 2013 was 0.80%. 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, 2013. See Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements for additional information.

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To mitigate residual risks relative to movements in electricity prices, the Company enters into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, financial hedge contracts for natural gas purchases. The Company continues to manage 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, 2012 when compared to the December 31, 2011 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.

The changes in fair value of energy-related derivative contracts, substantially all of which are composed of regulatory hedges, for the years ended December 31 were as follows:

	2012 Changes	2011 Changes
	Fair Value (in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	$(48)	$(38)
Contracts realized or settled	46	37
Current period changes[(a)]	(11)	(47)
Contracts outstanding at the end of the period, assets (liabilities), net	$(13)	$(48)

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

The changes in the fair value positions of the energy-related derivative contracts, which are substantially all attributable to both the volume and the price of natural gas, for the years ended December 31 were as follows:

	2012 Changes	2011 Changes
	Fair Value (in millions)	
Natural gas swaps	$30	$(5)
Natural gas options	5	(5)
Other energy-related derivatives	—	—
Total changes	$35	$(10)

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

	2012	2011
	mmBtu* Volume (in millions)	
Commodity – Natural gas swaps	45	30
Commodity – Natural gas options	12	9
Total hedge volume	57	39

*million British thermal units (mmBtu)

The weighted average swap contract cost above market prices was approximately $0.30 per mmBtu as of December 31, 2012 and $1.45 per mmBtu as of December 31, 2011. 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.

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At December 31, 2012 and 2011, 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, 2012 were as follows:

		Fair Value Measurements December 31, 2012	
	Total Fair Value	Maturity Year 1	Years 2&3
	(in millions)		
Level 1	$—	$ —	$ —
Level 2	(13)	(12)	(1)
Level 3	—	—	—
Fair value of contracts outstanding at end of period	$(13)	$(12)	$(1)

The Company is exposed to market price risk in the event of nonperformance by counterparties to energy-related and interest rate derivative contracts. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's 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 Company's construction program consists of a base level capital investment and capital expenditures to comply with existing environmental statutes and regulations, including the MATS rule. Over the next three years, the Company estimates spending, as part of its base level capital investment, $553 million on Plant Farley (including nuclear fuel), $895 million on distribution facilities, and $698 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 byproducts 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 byproducts rules over the 2013 through 2015 three-year period, based on the assumption that coal combustion byproducts will continue to be regulated as non-hazardous solid waste under the proposed rule, are estimated as follows:

	2013	2014	2015
Construction program:		(in millions)	
Base capital	$954	$1,117	$1,171
	195	424	411

Existing environmental statutes and regulations, including the MATS rule			
Total construction program base level capital investment	$1,149	$1,541	$1,582
Potential incremental environmental compliance investments:			
Proposed water and coal combustion byproducts rules	$5	$10	$160

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

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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 $704 million will be required by the end of 2015 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, 5, 6, 7, and 11 to the financial statements for additional information.

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Contractual Obligations

	2013	2014-2015	2016-2017	After 2017	Uncertain Timing[d]	Total
	(in millions)					
Long-term debt[a] —						
Principal	$250	$454	$761	$4,717	$—	$6,182
Interest	250	472	457	3,420	—	4,599
Preferred and preference stock dividends[b]	39	79	79	—	—	197
Financial derivative obligations[c]	14	4	—	—	—	18
Operating leases	20	20	13	9	—	62
Unrecognized tax benefits[d]	—	—	—	—	31	31
Purchase commitments —						
Capital[e]	1,028	2,754	—	—	—	3,782
Fuel[f]	1,385	2,088	646	560	—	4,679
Purchased power[g]	39	106	112	525	—	782
Other[h]	43	82	38	32	—	195
Pension and other postretirement benefit plans[i]	18	36	—	—	—	54
Total	$3,086	$6,095	$2,106	$9,263	$31	$20,581

(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, 2013, 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) The timing related to the realization of $31 million in unrecognized tax benefits in individual years beyond 12 months cannot be reasonably and reliably estimated due to uncertainties in the timing of the effective settlement of tax positions. See Note 5 to the financial statements under "Unrecognized Tax Benefits" for additional information.

(e) The Company provides estimated capital expenditures for a three-year period, including estimated capital expenditures and compliance costs associated with existing environmental regulations, including the MATS rule. Such amounts exclude the Company's estimates of potential incremental environmental compliance investment to comply with proposed water and coal combustion byproducts rules, which are approximately $5 million, $10 million, and $160 million for years 2013, 2014, and 2015, 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, 2012, 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, 2012.

(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.

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Cautionary Statement Regarding Forward Looking Statements

The Company's 2012 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 Tax Relief Act, 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 byproducts, and emissions of sulfur, nitrogen, carbon, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, financial reform legislation, 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, 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;
- investment performance of the Company's employee 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, 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.

STATEMENTS OF INCOME
For the Years Ended December 31, 2012, 2011, and 2010
Alabama Power Company 2012 Annual Report

	2012 (in millions)	2011	2010
Operating Revenues:			
Retail revenues	$4,933	$4,972	$5,076
Wholesale revenues, non-affiliates	277	287	465
Wholesale revenues, affiliates	111	244	236
Other revenues	199	199	199
Total operating revenues	5,520	5,702	5,976
Operating Expenses:			
Fuel	1,503	1,679	1,851
Purchased power, non-affiliates	73	73	72
Purchased power, affiliates	182	198	208
Other operations and maintenance	1,287	1,262	1,418
Depreciation and amortization	639	637	606
Taxes other than income taxes	340	339	332
Total operating expenses	4,024	4,188	4,487
Operating Income	1,496	1,514	1,489
Other Income and (Expense):			
Allowance for equity funds used during construction	19	22	36
Interest income	16	18	17
Interest expense, net of amounts capitalized	(287)	(299)	(303)
Other income (expense), net	(24)	(30)	(30)
Total other income and (expense)	(276)	(289)	(280)
Earnings Before Income Taxes	1,220	1,225	1,209
Income taxes	477	478	463
Net Income	743	747	746
Dividends on Preferred and Preference Stock	39	39	39
Net Income After Dividends on Preferred and Preference Stock	$704	$708	$707

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

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STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2012, 2011, and 2010
Alabama Power Company 2012 Annual Report

	2012	2011	2010
	(in millions)		
Net Income	$743	$747	$746
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $(7), $(5), and $-, respectively	(11)	(9)	—
Reclassification adjustment for amounts included in net income, net of tax of $1, $(1), and $(1), respectively	2	(2)	(2)
Total other comprehensive income (loss)	(9)	(11)	(2)
Comprehensive Income	$734	$736	$744

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

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STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2012, 2011, and 2010
Alabama Power Company 2012 Annual Report

	2012	2011	2010
	(in millions)		
Operating Activities:			
Net income	$743	$747	$746
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization, total	767	749	694
Deferred income taxes	164	459	410
Allowance for equity funds used during construction	(19)	(22)	(36)
Pension, postretirement, and other employee benefits	(11)	(32)	(15)
Pension and postretirement funding	(10)	(9)	(55)
Stock based compensation expense	9	6	5
Natural disaster reserve	3	34	52
Other, net	(27)	(41)	(27)
Changes in certain current assets and liabilities —			
-Receivables	23	18	(29)
-Fossil fuel stock	(132)	47	(1)
-Materials and supplies	(21)	(33)	(20)
-Other current assets	(4)	(6)	(4)
-Accounts payable	(77)	11	(54)
-Accrued taxes	(12)	157	(140)
-Accrued compensation	(3)	(12)	28
-Other current liabilities	(17)	(25)	(181)
Net cash provided from operating activities	1,376	2,048	1,373
Investing Activities:			
Property additions	(867)	(977)	(903)
Investment in restricted cash from pollution control bonds	1	4	—
Distribution of restricted cash from pollution control bonds	—	13	18
Nuclear decommissioning trust fund purchases	(194)	(350)	(237)
Nuclear decommissioning trust fund sales	193	349	236
Cost of removal net of salvage	(33)	(28)	(44)
Change in construction payables	12	(9)	(45)
Other investing activities	(46)	9	(12)
Net cash used for investing activities	(934)	(989)	(987)
Financing Activities:			
Proceeds —			
Capital contributions from parent company	27	12	28
Senior notes issuances	1,000	700	250
Redemptions —			
Pollution control revenue bonds	(1)	(4)	—
Senior notes	(950)	(750)	(250)
Payment of preferred and preference stock dividends	(39)	(39)	(39)
Payment of common stock dividends	(684)	(774)	(586)
Other financing activities	(2)	(14)	(3)

Net cash used for financing activities	(649)	(869)	(600)
Net Change in Cash and Cash Equivalents	(207)	190	(214)
Cash and Cash Equivalents at Beginning of Year	344	154	368
Cash and Cash Equivalents at End of Year	$137	$344	$154
Supplemental Cash Flow Information:			
Cash paid during the period for —			
Interest (net of $7, $9 and $14 capitalized, respectively)	$273	$286	$288
Income taxes (net of refunds)	309	(139)	188
Noncash transactions - accrued property additions at year-end	31	19	28

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

BALANCE SHEETS
At December 31, 2012 and 2011
Alabama Power Company 2012 Annual Report

Assets	2012	2011
	(in millions)	
Current Assets:		
Cash and cash equivalents	$137	$344
Restricted cash	—	1
Receivables —		
Customer accounts receivable	321	332
Unbilled revenues	138	126
Under recovered regulatory clause revenues	23	—
Other accounts and notes receivable	42	35
Affiliated companies	55	79
Accumulated provision for uncollectible accounts	(8)	(10)
Fossil fuel stock, at average cost	475	344
Materials and supplies, at average cost	395	375
Vacation pay	61	59
Prepaid expenses	81	74
Other regulatory assets, current	24	44
Other current assets	13	11
Total current assets	1,757	1,814
Property, Plant, and Equipment:		
In service	21,407	20,809
Less accumulated provision for depreciation	7,761	7,344
Plant in service, net of depreciation	13,646	13,465
Nuclear fuel, at amortized cost	354	330
Construction work in progress	438	374
Total property, plant, and equipment	14,438	14,169
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	53	62
Nuclear decommissioning trusts, at fair value	605	540
Miscellaneous property and investments	78	73
Total other property and investments	736	675
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	525	532
Prepaid pension costs	—	59
Deferred under recovered regulatory clause revenues	11	48
Other regulatory assets, deferred	1,083	994
Other deferred charges and assets	162	186
Total deferred charges and other assets	1,781	1,819
Total Assets	$18,712	$18,477

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

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BALANCE SHEETS
At December 31, 2012 and 2011
Alabama Power Company 2012 Annual Report

Liabilities and Stockholder's Equity	2012	2011
	(in millions)	
Current Liabilities:		
Securities due within one year	$250	$500
Accounts payable —		
Affiliated	191	203
Other	318	322
Customer deposits	85	85
Accrued taxes —		
Accrued income taxes	5	32
Other accrued taxes	33	34
Accrued interest	62	63
Accrued vacation pay	50	48
Accrued compensation	94	95
Liabilities from risk management activities	14	54
Other regulatory liabilities, current	3	18
Other current liabilities	38	38
Total current liabilities	1,143	1,492
Long-Term Debt (See accompanying statements)	5,929	5,632
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	3,404	3,257
Deferred credits related to income taxes	79	83
Accumulated deferred investment tax credits	141	149
Employee benefit obligations	321	343
Asset retirement obligations	589	553
Other cost of removal obligations	759	703
Other regulatory liabilities, deferred	183	156
Other deferred credits and liabilities	81	82
Total deferred credits and other liabilities	5,557	5,326
Total Liabilities	12,629	12,450
Redeemable Preferred Stock (See accompanying statements)	342	342
Preference Stock (See accompanying statements)	343	343
Common Stockholder's Equity (See accompanying statements)	5,398	5,342
Total Liabilities and Stockholder's Equity	$18,712	$18,477
Commitments and Contingent Matters (See notes)		

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

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STATEMENTS OF CAPITALIZATION
At December 31, 2012 and 2011
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	2012	2011	2012	2011
	(in millions)		(percent of total)	
Long-Term Debt:				
Long-term debt payable to affiliated trusts —				
Variable rate (3.41% at 1/1/13) due 2042	$206	$206		
Long-term notes payable —				
4.85% due 2012	—	500		
5.80% due 2013	250	250		
0.55% due 2015	400	—		
5.20% due 2016	200	200		
5.50% to 5.55% due 2017	525	525		
3.375% to 6.125% due 2019-2047	3,450	3,300		
Total long-term notes payable	4,825	4,775		
Other long-term debt —				
Pollution control revenue bonds —				
0.58% to 5.00% due 2034	367	367		
Variable rate (0.13% at 1/1/13) due 2015	54	54		
Variable rates (0.13% to 0.17% at 1/1/13) due 2017	36	36		
Variable rates (0.08% to 0.20% at 1/1/13) due 2021-2038	694	694		
Total other long-term debt	1,151	1,151		
Unamortized debt premium (discount), net	(3)	—		
Total long-term debt (annual interest requirement — $250 million)	6,179	6,132		
Less amount due within one year	250	500		
Long-term debt excluding amount due within one year	5,929	5,632	49.4%	48.4%

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STATEMENTS OF CAPITALIZATION (continued)
At December 31, 2012 and 2011
Alabama Power Company 2012 Annual Report

	2012	2011	2012	2011
	(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	2.8	2.9
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	2.9	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	2,227	2,182		
Retained earnings	1,976	1,956		
Accumulated other comprehensive income (loss)	(27)	(18)		
Total common stockholder's equity	5,398	5,342	44.9	45.8
Total Capitalization	$12,012	$11,659	100.0 %	100.0 %

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

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STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
For the Years Ended December 31, 2012, 2011, and 2010
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	Number of Common Shares Issued (in millions)	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance at December 31, 2009	31	$1,222	$2,119	$1,901	$(5)	$5,237
Net income after dividends on preferred and preference stock	—	—	—	707	—	707
Capital contributions from parent company	—	—	37	—	—	37
Other comprehensive income (loss)	—	—	—	—	(2)	(2)
Cash dividends on common stock	—	—	—	(586)	—	(586)
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

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

NOTES TO FINANCIAL STATEMENTS
Alabama Power Company 2012 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 and power pool transactions. Costs for these services amounted to $340 million, $347 million, and $371 million during 2012, 2011, and 2010, 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 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 $218 million, $215 million, and $218 million during 2012, 2011, and 2010, 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 $12 million in 2012, $12 million in 2011, and

$11 million in 2010. Also, Mississippi Power reimburses the Company for any direct fuel purchases delivered from one of the Company's transfer facilities, which were $28 million in 2012, $21 million in 2011, and $16 million in 2010. See Note 4 for additional information.

Due to the expiration of the Plant Harris power purchase agreement (PPA) with Southern Power in 2010, no purchased power costs or fuel costs were recognized in 2012 or 2011 associated with this PPA. Additionally, the Company recorded no prepaid capacity expenses in 2012 or 2011. The Company's purchased power costs from Plant Harris in 2010 totaled $15 million. The Company also provided the fuel, at cost, associated with the PPA totaling $21 million in 2010. See Note 7 under "Fuel and Purchased Power Agreements" 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 $38 million in 2012, $22 million in 2013, and $29 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.

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 2012, 2011, or 2010.

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.

New Accounting Pronouncements

In June 2011, the Financial Accounting Standards Board (FASB) issued guidance, ASU 2011-05, Presentation of Comprehensive Income, requiring companies to present the total of comprehensive income, the components of net income, and the components of other comprehensive income, in a single continuous statement of comprehensive income or in two separate but consecutive statements. In October 2012, the FASB issued additional guidance, ASU 2012-04, Technical Corrections and Improvements (ASU 2012-04), in which it clarified that those companies presenting consecutive statements must begin the statement of comprehensive income with net income. The Company retroactively adopted the guidance in ASU 2012-04 beginning with its financial statements for the three years ended December 31, 2012, 2011, and 2010.

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NOTES (continued)
Alabama Power Company 2012 Annual Report

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

	2012	2011	Note
	(in millions)		
Deferred income tax charges	$525	$532	(a,k)
Loss on reacquired debt	93	84	(b)
Vacation pay	61	59	(c,j)
Under/(over) recovered regulatory clause revenues	34	47	(d)
Fuel hedging (realized and unrealized) losses	18	48	(e)
Other regulatory assets	51	46	(f,l)
Asset retirement obligations	(64)	(35)	(a)
Other cost of removal obligations	(759)	(703)	(a)
Deferred income tax credits	(79)	(83)	(a)
Fuel hedging (realized and unrealized) gains	(5)	(1)	(e)
Mine reclamation and remediation	(8)	(8)	(g)
Nuclear outage	33	38	(d)
Natural disaster reserve	(103)	(110)	(h)
Other regulatory liabilities	(5)	(20)	(d,l)
Retiree benefit plans	911	822	(i,j)
Total regulatory assets (liabilities), net	$703	$716	

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 five 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) Recorded as accepted by the Alabama PSC. Capitalized upon initialization of related construction projects, if applicable.

(g) 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 is $21 million 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) Recovered and amortized as approved or accepted by the Alabama PSC over the life of the contract.

NOTES (continued)
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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 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, 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 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:

	2012	2011
	(in millions)	
Generation	$11,110	$10,982
Transmission	3,137	2,998
Distribution	5,714	5,517
General	1,434	1,300

Plant acquisition adjustment	12	12
Total plant in service	$21,407	$20,809

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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 expense 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 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. The 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. The total unamortized deferred nuclear outage expense balance of $33 million is included in the 2012 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 2012, 3.3% in 2011, and 3.3% in 2010. 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 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 range of time over which the Company may settle these obligations is unknown and cannot be reasonably estimated. 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:

	2012	2011

	(in millions)	
Balance at beginning of year	$553	$520
Liabilities incurred	—	—
Liabilities settled	(1)	(2)
Accretion	37	35
Balance at end of year	$589	$553

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Nuclear Decommissioning
The 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, 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. At December 31, 2011, investment securities in the Funds totaled $539 million consisting of equity securities of $382 million, debt securities of $146 million, and $11 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 $193 million, $349 million, and $236 million in 2012, 2011, and 2010, respectively, all of which were reinvested. 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. For 2010, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $65 million, of which $31 million related to securities held in the Funds at December 31, 2010. 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, 2012, the accumulated provisions for decommissioning were as follows:

	(in millions)
External trust funds	$604
Internal reserves	22
Total	$626

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Site study cost is the estimate to decommission a facility as of the site study year. The estimated costs of decommissioning based on the most current study performed in 2008 for Plant Farley are as follows:

Decommissioning periods:	
Beginning year	2037
Completion year	2065
	(in millions)
Site study costs:	
Radiated structures	$1,060
Non-radiated structures	72
Total site study costs	$1,132

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 2013.

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 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 9.4% in 2012, 9.2% in 2011, and 9.4% in 2010. AFUDC, net of income taxes, as a percent of net income after dividends on preferred and preference stock was 3.3% in 2012, 3.9% in 2011, and 6.3% in 2010.

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 "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 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. Any material 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, 2012.

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.

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Variable Interest Entities

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

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

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions to the qualified pension plan were made for the year ended December 31, 2012. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2013. The Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The Company funds its other postretirement trusts to the extent required by the Alabama PSC and the FERC. For the year ending December 31, 2013, other postretirement trust contributions are expected to total approximately $4 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 2009 for the 2010 plan year using discount rates for the pension plans and the other postretirement benefit plans of 5.93% and 5.84%, respectively, and an annual salary increase of 4.18%.

	2012		2011		2010	
Discount rate:						
Pension plans	4.27	%	4.98	%	5.52	%
Other postretirement benefit plans	4.06		4.88		5.41	
Annual salary increase	3.59		3.84		3.84	
Long-term return on plan assets:						
Pension plans	8.20		8.45		8.45	
Other postretirement benefit plans	7.19		7.39		7.43	

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.

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An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) is the weighted average medical care cost trend rate. The weighted average medical care cost trend rates used in measuring the APBO as of December 31, 2012 were as follows:

	Initial Cost Trend Rate	Ultimate Cost Trend Rate	Year That Ultimate Rate Is Reached
Pre-65	8.00%	5.00%	2020
Post-65 medical	6.00	5.00	2020
Post-65 prescription	6.00	5.00	2020

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, 2012 as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$32	$(27)
Service and interest costs	2	(1)

Pension Plans

The total accumulated benefit obligation for the pension plans was $2.0 billion at December 31, 2012 and $1.8 billion at December 31, 2011. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2012 and 2011 were as follows:

	2012	2011
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	$1,932	$1,779
Service cost	44	43
Interest cost	94	96
Benefits paid	(90)	(88)
Actuarial loss	238	102
Balance at end of year	2,218	1,932
Change in plan assets		
Fair value of plan assets at beginning of year	1,885	1,933
Actual return on plan assets	274	32
Employer contributions	8	8
Benefits paid	(90)	(88)
Fair value of plan assets at end of year	2,077	1,885
Accrued liability	$(141)	$(47)

At December 31, 2012, the projected benefit obligations for the qualified and non-qualified pension plans were $2.1 billion and $121 million, respectively. All pension plan assets are related to the qualified pension plan.

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Amounts recognized in the balance sheets at December 31, 2012 and 2011 related to the Company's pension plans consist of the following:

	2012	2011
	(in millions)	
Prepaid pension costs	$—	$59
Other regulatory assets, deferred	822	727
Other current liabilities	(8)	(7)
Employee benefit obligations	(133)	(99)

Presented below are the amounts included in regulatory assets at December 31, 2012 and 2011 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 2013.

	2012	2011	Estimated Amortization in 2013
		(in millions)	
Prior service cost	$26	$33	$7
Net (gain) loss	796	694	52
Other regulatory assets, deferred	$822	$727	

The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2012 and 2011 are presented in the following table:

	Regulatory Assets
	(in millions)
Balance at December 31, 2010	$497
Net (gain) loss	243
Change in prior service costs	—
Reclassification adjustments:	
Amortization of prior service costs	(9)
Amortization of net gain (loss)	(4)
Total reclassification adjustments	(13)
Total change	230
Balance at December 31, 2011	$727
Net (gain) loss	125
Change in prior service costs	—
Reclassification adjustments:	
Amortization of prior service costs	(7)
Amortization of net gain (loss)	(23)
Total reclassification adjustments	(30)
Total change	95
Balance at December 31, 2012	$822

Components of net periodic pension cost (income) were as follows:

	2012	2011	2010
	(in millions)		
Service cost	$44	$43	$41
Interest cost	94	96	97
Expected return on plan assets	(162)	(173)	(168)
Recognized net (gain) loss	23	4	2
Net amortization	7	9	9
Net periodic pension cost (income)	$6	$(21)	$(19)

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, 2012, estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2013	$99
2014	104
2015	108
2016	112
2017	117
2018 to 2022	637

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Other Postretirement Benefits
Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2012 and 2011 were as follows:

	2012	2011
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	$470	$454
Service cost	5	5
Interest cost	22	24
Benefits paid	(24)	(27)
Actuarial loss	15	11
Plan amendments	—	—
Retiree drug subsidy	2	3
Balance at end of year	490	470
Change in plan assets		
Fair value of plan assets at beginning of year	315	323
Actual return on plan assets	39	5
Employer contributions	11	11
Benefits paid	(22)	(24)
Fair value of plan assets at end of year	343	315
Accrued liability	$(147)	$(155)

Amounts recognized in the balance sheets at December 31, 2012 and 2011 related to the Company's other postretirement benefit plans consist of the following:

	2012	2011
	(in millions)	
Regulatory assets	$89	$96
Employee benefit obligations	(147)	(155)

Presented below are the amounts included in regulatory assets at December 31, 2012 and 2011 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 2013.

	2012	2011	Estimated Amortization in 2013
	(in millions)		
Prior service cost	$22	$26	$4
Net (gain) loss	67	68	2
Transition obligation	—	2	—
Regulatory assets	$89	$96	

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The changes in the balance of regulatory assets related to the other postretirement benefit plans for the plan years ended December 31, 2012 and 2011 are presented in the following table:

	Regulatory Assets
	(in millions)
Balance at December 31, 2010	$72
Net (gain) loss	31
Change in prior service costs/transition obligation	—
Reclassification adjustments:	
Amortization of transition obligation	(3)
Amortization of prior service costs	(4)
Amortization of net gain (loss)	—
Total reclassification adjustments	(7)
Total change	24
Balance at December 31, 2011	$96
Net (gain) loss	(1)
Change in prior service costs/transition obligation	—
Reclassification adjustments:	
Amortization of transition obligation	(2)
Amortization of prior service costs	(4)
Amortization of net gain (loss)	—
Total reclassification adjustments	(6)
Total change	(7)
Balance at December 31, 2012	$89

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

	2012	2011	2010
	(in millions)		
Service cost	$5	$5	$6
Interest cost	22	24	26
Expected return on plan assets	(23)	(25)	(25)
Net amortization	6	7	7
Net postretirement cost	$10	$11	$14

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Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the APBO for the other postretirement benefit plans. 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)		
2013	$30	$(3)	$27
2014	32	(4)	28
2015	33	(4)	29
2016	34	(4)	30
2017	35	(5)	30
2018 to 2022	176	(26)	150

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, 2012 and 2011, along with the targeted mix of assets for each plan, is presented below:

	Target	2012	2011
Pension plan assets:			
Domestic equity	26 %	28 %	29 %
International equity	25	24	25
Fixed income	23	27	23
Special situations	3	1	—
Real estate investments	14	13	14
Private equity	9	7	9
Total	100 %	100 %	100 %
Other postretirement benefit plan assets:			
Domestic equity	44 %	46 %	41 %
International equity	20	20	14
Domestic fixed income	24	28	38
Special situations	1	—	—
Real estate investments	8	4	4
Private equity	3	2	3
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, 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, 2012 and 2011. 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:

- Investments in equity securities: 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.
- Investments in fixed income securities: 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.
- Investments in 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.
- Investments in private equity and real estate: 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.

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The fair values of pension plan assets as of December 31, 2012 and 2011 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, 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:				
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.

NOTES (continued)
Alabama Power Company 2012 Annual Report

As of December 31, 2011:	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*	$320	$148	$—	$468
International equity*	329	94	—	423
Fixed income:				
U.S. Treasury, government, and agency bonds	—	120	—	120
Mortgage- and asset-backed securities	—	37	—	37
Corporate bonds	—	232	1	233
Pooled funds	—	105	—	105
Cash equivalents and other	—	39	—	39
Real estate investments	61	—	217	278
Private equity	—	—	161	161
Total	$710	$775	$379	$1,864

* 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, 2012 and 2011 were as follows:

	2012 Real Estate Investments	Private Equity	2011 Real Estate Investments	Private Equity
	(in millions)			
Beginning balance	$217	$161	$191	$180
Actual return on investments:				
Related to investments held at year end	2	—	16	(3)
Related to investments sold during the year	1	2	6	9
Total return on investments	3	2	22	6
Purchases, sales, and settlements	—	(8)	4	(25)
Transfers into/out of Level 3	—	—	—	—
Ending balance	$220	$155	$217	$161

The fair values of other postretirement benefit plan assets as of December 31, 2012 and 2011 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 2012 Annual Report

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.

As of December 31, 2011:	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*	$57	$8	$—	$65
International equity*	17	5	—	22
Fixed income:				
U.S. Treasury, government, and agency bonds	—	9	—	9
Mortgage- and asset-backed securities	—	2	—	2
Corporate bonds	—	12	—	12
Pooled funds	—	5	—	5
Cash equivalents and other	—	19	—	19
Trust-owned life insurance	—	160	—	160
Real estate investments	4	—	11	15
Private equity	—	—	8	8
Total	$78	$220	$19	$317

* 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)
Alabama Power Company 2012 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, 2012 and 2011 were as follows:

	2012 Real Estate Investments (in millions)	Private Equity	2011 Real Estate Investments	Private Equity
Beginning balance	$11	$8	$10	$9
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)
Transfers into/out of Level 3	—	—	—	—
Ending balance	$11	$8	$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 2012, 2011, and 2010 were $19 million, $18 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 byproducts, 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

In 1999, the EPA brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including the Company, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. The EPA alleged NSR violations at five coal-fired generating facilities operated by the Company and three coal-fired generating facilities operated by Georgia Power. The civil action sought penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. The case against Georgia Power was administratively closed in 2001 and has not been reopened. After the Company was dismissed from the original action, the EPA filed a separate action in 2001 against the Company in the U.S. District Court for the Northern District of Alabama.

In 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree, resolving claims relating to the alleged NSR violations at Plant Miller. In 2010, the EPA dismissed five of its eight remaining claims against the Company, leaving only three claims, including one relating to a unit co-owned by Mississippi Power. In March 2011, the U.S. District Court for the Northern District of Alabama granted the Company summary judgment on all remaining claims and dismissed the case with prejudice. That judgment is on appeal to the U.S. Court of Appeals for the Eleventh Circuit. On February 23, 2012, the EPA filed a motion in the U.S. District Court for the Northern District of Alabama seeking vacatur of the judgment and recusal of the judge in the case involving the Company.

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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.

Climate Change Litigation

Kivalina Case

In 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs allege that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that some of the defendants (including Southern Company) acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. In 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case. On September 21, 2012, the U.S. Court of Appeals for the Ninth Circuit upheld the U.S. District Court for the Northern District of California's dismissal of the case. On November 27, 2012, the U.S. Court of Appeals for the Ninth Circuit denied the plaintiffs' request for review of the decision. On February 25, 2013, the plaintiffs filed a petition for writ of certiorari with the U.S. Supreme Court. Southern Company believes that these claims are without merit. While Southern Company believes the likelihood of loss is remote based on existing case law, it is not possible to predict with certainty whether the Company will incur any liability in connection with this matter. The ultimate outcome of this matter cannot be determined at this time.

Hurricane Katrina Case

In 2005, immediately following Hurricane Katrina, a lawsuit was filed in the U.S. District Court for the Southern District of Mississippi by Ned Comer on behalf of Mississippi residents seeking recovery for property damage and personal injuries caused by Hurricane Katrina. In 2006, the plaintiffs amended the complaint to include Southern Company and many other electric utilities, oil companies, chemical companies, and coal producers. The plaintiffs allege that the defendants contributed to climate change, which contributed to the intensity of Hurricane Katrina. In 2007, the U.S. District Court for the Southern District of Mississippi dismissed the case. On appeal to the U.S. Court of Appeals for the Fifth Circuit, a three-judge panel reversed the U.S. District Court for the Southern District of Mississippi, holding that the case could proceed, but, on rehearing, the full U.S. Court of Appeals for the Fifth Circuit dismissed the plaintiffs' appeal, resulting in reinstatement of the decision of the U.S. District Court for the Southern District of Mississippi in favor of the defendants. In May 2011, the plaintiffs filed an amended version of their class action complaint, arguing that the earlier dismissal was on procedural grounds and under Mississippi law the plaintiffs have a right to re-file. The amended complaint was also filed against numerous chemical, coal, oil, and utility companies, including the Company. On March 20, 2012, the U.S. District Court for the Southern District of Mississippi dismissed the plaintiffs' amended complaint. On April 16, 2012, the plaintiffs appealed the case to the U.S. Court of Appeals for the Fifth Circuit. The Company believes that these claims are without merit. While the Company believes the likelihood of loss is remote based on existing case law, it is not possible to predict with certainty whether the Company will incur any liability in connection with this matter. 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 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.

NOTES (continued)
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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 substantially all 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 accrue until the issue is resolved or storage is provided. No amounts have been recognized in the financial statements as of December 31, 2012 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 July 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 April 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%. Retail rates remain unchanged when the retail return on common equity (ROE) is projected to be between 13.0% and 14.5%. If the Company's actual retail ROE 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 ROE fall below the allowed equity return range.

In 2011 and 2012, retail rates under Rate RSE remained unchanged from 2010. On November 30, 2012, the Company made its Rate RSE submission to the Alabama PSC of projected data for calendar year 2013; projected earnings were within the specified return range, and, therefore, retail rates under Rate RSE remained unchanged for 2013. Under the terms of Rate RSE, the maximum possible increase for 2014 is 5.00%. However, the Company is working with the Alabama PSC to develop a plan that will potentially preclude the need for a Rate RSE increase in 2014. The ultimate outcome of this matter cannot be determined at this time.

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). Effective April 2011, Rate CNP PPA was reduced by approximately $5 million annually. On March 6, 2012, 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, 2012 through March 31, 2013. It is anticipated that no adjustment will be made to Rate CNP PPA in 2013. As of December 31, 2012, the Company had an under recovered certificated PPA balance of $9 million, $7 million of which is included in deferred under recovered regulatory clause revenues and $2 million of which is included in under recovered regulatory clause revenues in the balance sheet.

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On September 17, 2012, the Alabama PSC approved and certificated a PPA for the purchase of approximately 200 megawatts (MWs) of the approximately 400 MWs of energy from wind-powered generating facilities and all associated environmental attributes, including renewable energy credits. The terms of this PPA and a previously approved and certificated PPA 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, to third parties. Approximately 200 MWs of energy from wind-powered generating facilities was operational in December 2012.

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 to recover environmental costs in 2011 or 2012. On November 26, 2012, 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 less than $1 million, which is to be recovered in the billing months of January 2013 through December 2013. On December 4, 2012, the Alabama PSC issued a consent order that the Company leave in effect for 2013 the factors associated with the Company's environmental compliance costs for the year 2012. Any unrecovered amounts associated with 2013 will be reflected in the 2014 filing. As of December 31, 2012, the Company had an under recovered environmental clause balance of $21 million which is included in under recovered regulatory clause revenues in the balance sheet.

Environmental Accounting Order

Proposed and final environmental regulations could result in significant additional compliance costs that could affect future unit retirement and replacement decisions. In September 2011, the Alabama PSC approved an order allowing for the establishment of a regulatory asset to record the unrecovered investment costs associated with any such decisions, including the unrecovered plant asset balance and the unrecovered costs associated with site removal and closure. 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

On November 6, 2012, the Alabama PSC approved an accounting order for certain compliance-related operation and maintenance expenditures for the years 2013 through 2017, as well as the incremental increase in operation expense related to pension cost for 2013. Under the accounting order, expenses from January 2013 through December 2017 related to compliance with standards addressing Critical Infrastructure Protection issued by the North American Electric Reliability Corporation and cyber security requirements issued by the NRC will be deferred to a regulatory asset account and amortized over a three-year period beginning in January 2015. Expenses from January 2013 through December 2017 related to compliance with NRC guidance addressing the readiness at nuclear facilities within the U.S., as prompted by the earthquake and tsunami that struck Japan in March 2011, also will be deferred as a regulatory asset and recovered over the same amortization period. The compliance-related expenses to be afforded regulatory asset treatment over the five-year period are currently estimated to be approximately $43 million. In addition, the accounting order authorizes the Company to defer an incremental increase in its pension cost for 2013. That increased pension cost is estimated to be approximately $17 million. During 2013, the actual incremental increase will be deferred to a regulatory asset account and will be amortized over a three-year period beginning in January 2015. Pursuant to the accounting order, the Company has the ability to accelerate the amortization of the regulatory assets.

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 4, 2012, the Alabama PSC issued a consent order that the Company leave in effect the energy cost recovery rates which began in April 2011 for 2013. Therefore, the Rate ECR factor as of January 1, 2013 remained at 2.681 cents per KWH. Effective with billings beginning in January 2014, the Rate ECR factor will be 5.910 cents per KWH, absent a further order from the Alabama PSC.

NOTES (continued)
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As of December 31, 2012 and 2011, the Company had under recovered fuel balances of approximately $4 million and $31 million, respectively, which are included in deferred under recovered regulatory clause revenues in the balance sheets. This classification is 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.

During the first half of 2011, multiple storms caused varying degrees of damage to the Company's transmission and distribution facilities. The most significant storms occurred in April 2011, causing over 400,000 of the Company's 1.4 million customers to be without electrical service. The cost of repairing the damage to facilities and restoring electrical service to customers as a result of these storms was $42 million for operations and maintenance expenses and $161 million for capital-related expenditures.

In accordance with the order that was issued by the Alabama PSC in July 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, 2012 and December 31, 2011 were approximately $103 million and $110 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 2010, the Alabama PSC approved a change to the nuclear maintenance outage accounting process associated with routine refueling activities. Previously, the Company accrued nuclear outage operations and maintenance expenses for the two units at Plant Farley during the 18-month cycle for the outages. In accordance with the 2010 order, nuclear outage expenses are deferred when the charges actually occur and then amortized over the subsequent 18-month period.

The initial result of implementation of the accounting order was that no nuclear maintenance outage expenses were recognized from January 2011 through December 2011, which decreased nuclear outage operations and maintenance expenses in 2011 from 2010 by approximately $50 million. During the fall of 2011, approximately $38 million of actual nuclear outage expenses associated with one unit at Plant Farley was deferred to a regulatory asset account; beginning in January 2012, these deferred costs are being amortized to nuclear operations and maintenance expenses over an 18-month period. During the spring of 2012, approximately $31 million of actual nuclear outage expenses associated with the second unit at Plant Farley was deferred to a regulatory asset account; beginning in July 2012, these deferred costs are being amortized to nuclear operations and maintenance expenses 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 existing order.

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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 a return on equity. The Company's share of purchased power totaled $109 million in 2012, $142 million in 2011, and $101 million in 2010, 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. Also, the Company has guaranteed $50 million principal amount of unsecured senior notes issued by SEGCO for general corporate purposes. These senior notes mature 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 guaranty.

At December 31, 2012, the capitalization of SEGCO consisted of $82 million of equity and $75 million of long-term debt on which the annual interest requirement is $3 million. In addition, SEGCO had short-term debt outstanding of $45 million. SEGCO paid dividends of $14 million in 2012, $15 million in 2011, and $5 million in 2010, 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 and developing 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, 2012, the Company's portion of the construction work in progress associated with the construction of the pipeline is $0.1 million.

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, 2012 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)	$151	$ 89	$9
Plant Miller Units 1 and 2	1,320	91.84%	(2)	1,401	551	8

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

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 subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more current expense than would be paid if it filed a separate income tax return. In accordance with IRS regulations, each company is jointly and severally liable for the federal tax liability.

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Current and Deferred Income Taxes
Details of income tax provisions are as follows:

	2012	2011	2010
	(in millions)		
Federal —			
Current	$262	$20	$52
Deferred	137	377	333
	399	397	385
State —			
Current	51	(1)	1
Deferred	27	82	77
	78	81	78
Total	$477	$478	$463

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:

	2012	2011
	(in millions)	
Deferred tax liabilities —		
Accelerated depreciation	$2,989	$2,820
Property basis differences	420	439
Premium on reacquired debt	36	33
Employee benefit obligations	218	217
Under recovered energy clause	16	26
Regulatory assets associated with employee benefit obligations	378	343
Regulatory assets associated with asset retirement obligations	248	233
Other	114	94
Total	4,419	4,205
Deferred tax assets —		
Federal effect of state deferred taxes	194	186
State effect of federal deferred taxes	—	—
Unbilled fuel revenue	39	38
Storm reserve	34	38
Employee benefit obligations	408	373
Other comprehensive losses	19	14
Asset retirement obligations	248	233
Other	98	97
Total	1,040	979
Total deferred tax liabilities, net	3,379	3,226
Portion included in current assets (liabilities), net	25	31
Accumulated deferred income taxes	$3,404	$3,257

NOTES (continued)
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At December 31, 2012, the Company's tax-related regulatory assets to be recovered from customers were $525 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, 2012, the Company's tax-related regulatory liabilities to be credited to customers were $79 million. These liabilities are primarily attributable to unamortized investment tax credits.

In accordance with regulatory requirements, deferred investment tax credits 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 2012, 2011, and 2010. At December 31, 2012, all investment tax credits 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 to be placed in service in 2013). The application of the bonus depreciation provisions in the Tax Relief Act significantly increased deferred tax liabilities related to accelerated depreciation.

Effective Tax Rate

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

	2012	2011	2010
Federal statutory rate	35.0%	35.0%	35.0%
State income tax, net of federal deduction	4.1	4.3	4.2
Non-deductible book depreciation	0.9	0.8	0.8
Differences in prior years' deferred and current tax rates	(0.1)	(0.1)	(0.1)
AFUDC equity	(0.5)	(0.6)	(1.0)
Other	(0.3)	(0.4)	(0.6)
Effective income tax rate	39.1%	39.0%	38.3%

The increase in the Company's 2012 effective tax rate was not material.

The increase in the Company's 2011 effective tax rate was due to a decrease in the tax benefit of AFUDC equity due to a decrease in AFUDC, resulting from the completion of construction projects related to environmental mandates at generating facilities. See Note 1 under "Allowance for Funds Used During Construction" for additional information.

Unrecognized Tax Benefits

For 2012, the total amount of unrecognized tax benefits decreased by $1 million, resulting in a balance of $31 million as of December 31, 2012.

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

	2012	2011	2010
		(in millions)	
Unrecognized tax benefits at beginning of year	$32	$43	$6
Tax positions from current periods	5	6	6
Tax positions from prior periods	(4)	(17)	31
Reductions due to settlements	(2)	—	—
Balance at end of year	$31	$32	$43

NOTES (continued)
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The tax positions from current periods for 2012 relate primarily to the tax accounting method change for repairs-generation assets. See "Tax Method of Accounting for Repairs" herein for additional information. The American Jobs Creation Act of 2004 created a tax deduction for a portion of income attributable to U.S. production activities as defined in Section 199 of the Internal Revenue Code (production activities deduction). The tax positions decrease from prior periods and the reductions due to settlements for 2012 relate to a settlement with the IRS of the calculation methodology for the production activities deduction.

The impact on the Company's effective tax rate, if recognized, was as follows:

	2012	2011	2010
		(in millions)	
Tax positions impacting the effective tax rate	$—	$5	$6
Tax positions not impacting the effective tax rate	31	27	37
Balance of unrecognized tax benefits	$31	$32	$43

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:

	2012	2011	2010
		(in millions)	
Interest accrued at beginning of year	$1.9	$1.5	$0.3
Interest reclassified due to settlements	(1.9)	—	—
Interest accrued during the year	—	0.4	1.2
Balance at end of year	$—	$1.9	$1.5

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 associated with a majority of the Company's unrecognized tax positions will significantly increase or decrease within 12 months. The resolution of the tax accounting method change for repairs-generation assets, as well as the conclusion or settlement of 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 audited and closed all of Southern Company's consolidated federal income tax returns prior to 2009 and has settled its audits of Southern Company's consolidated federal income tax returns for 2009 and 2010, in principle, pending final approval. Additionally, the IRS has audited and closed Southern Company's 2011 consolidated federal income tax return. For tax years 2010 through 2013, Southern Company is a participant in the Compliance Assurance Process of the IRS. The audits for the Company's state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2007.

Tax Method of Accounting for Repairs

Southern Company submitted a tax accounting method change related to the deductibility of repair costs associated with its subsidiaries' generation, transmission, and distribution systems effective for the 2009 consolidated federal income tax return in 2010. In August 2011, the IRS issued a revenue procedure, which provides a safe harbor method of accounting that taxpayers may use to determine eligible repair costs for transmission and distribution property. The IRS continues to work with the utility industry in an effort to define eligible repair costs for generation assets in a consistent manner for all utilities. 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. The utility industry anticipates more detailed guidance concerning these regulations. Due to the uncertainty regarding the ultimate resolution of the repair costs for generation assets, an unrecognized tax position has been recorded for the tax accounting method change for repairs-generation assets. The ultimate outcome of this matter cannot be determined at this time; however, it is not expected to materially impact net income.

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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, 2012 and December 31, 2011, which constitute substantially all of the assets of this trust and are reflected in the balance sheets as long-term debt payable. The Company considers that the mechanisms and obligations relating to the preferred securities issued for its benefit, taken together, constitute a full and unconditional guarantee by it of the trust's payment obligations with respect to these securities. At December 31, 2012 and 2011, 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, 2012 and 2011, the Company had scheduled maturities of senior notes due within one year totaling $250 million and $500 million, respectively.
Maturities of senior notes and pollution control revenue bonds through 2017 applicable to total long-term debt are as follows: $250 million in 2013; $454 million in 2015; $200 million in 2016; and $561 million in 2017. There are no scheduled maturities in 2014.
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 2012. In 2012, the Company redeemed approximately $0.7 million of The Industrial Development Board of the Town of West Jefferson Solid Waste Disposal Revenue Bonds (Alabama Power Company Miller Plant Project), Series 2008. The amount of tax-exempt pollution control revenue bonds outstanding at both December 31, 2012 and 2011 was $1.2 billion. Proceeds from certain issuances are restricted until qualifying expenditures are incurred.
Senior Notes
The Company issued a total of $1.0 billion of unsecured senior notes in 2012. The proceeds of these issuances were used for general corporate purposes, including the Company's continuous construction program, to redeem $450 million of unsecured senior notes in 2012, and to pay at maturity $500 million of unsecured senior notes in 2012.
At both December 31, 2012 and 2011, the Company had $4.8 billion of senior notes outstanding. These senior notes are effectively subordinated to all secured debt of the Company which amounted to approximately $153 million at December 31, 2012.
Preferred, Preference, and Common Stock
In 2012, the Company issued no new shares of preferred stock, preference stock, or common stock.
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.

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The Company's preferred stock is subject to redemption at a price equal to the par value plus a premium. The Company's Class A preferred stock is subject to redemption at a price equal to the stated capital. 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, 2012. 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.

Bank Credit Arrangements
At December 31, 2012, committed credit arrangements with banks were as follows:

Expires[(a)]					Executable Term-Loans		Due Within One Year	
2013	2014	2016	Total	Unused	One Year	Two Years	Term Out	No Term Out
			(in millions)					
$158	$350	$800	$1,308	$1,308	$56	$—	$56	$102

(a) No credit arrangements expire in 2015.

NOTES (continued)
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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, 2012, the Company was in compliance with the debt limit covenants.

In addition, the credit arrangements typically contain cross default provisions that are restricted to indebtedness (including guaranteed obligations) of the Company. The Company is currently in compliance with all such covenants. None of the arrangements contain material adverse change clauses at the time of borrowings.

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. During 2012, the Company remarketed $207 million of pollution control revenue bonds. The amount of variable rate pollution control revenue bonds requiring liquidity support was $793 million as of December 31, 2012.

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, 2012 and 2011, there was no short-term debt outstanding. At December 31, 2012, the Company had regulatory approval to have outstanding up to $2.3 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 of fossil and nuclear fuel which are not recognized on the balance sheets. In 2012, 2011, and 2010, the Company incurred fuel expense of $1.5 billion, $1.7 billion, and $1.9 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 expense under PPAs accounted for as operating leases was $33 million, $33 million, and $30 million for 2012, 2011, and 2010, respectively. Total estimated minimum long-term obligations at December 31, 2012 were as follows:

	Commitments Non-Affiliated (in millions)
2013	$31
2014	37
2015	38
2016	39
2017	40
2018 and thereafter	223
Total commitments	$408

Certain PPAs reflected in the table are accounted for as operating leases.

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. The credit rating of Southern Power is currently below that of the traditional operating companies. 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.

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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 $24 million in 2012, $23 million in 2011, and $25 million in 2010. Of these amounts, $19 million, $18 million, and $20 million for 2012, 2011, and 2010, respectively, relate to the railcar leases and are recoverable through the Company's Rate ECR. As of December 31, 2012, estimated minimum lease payments under operating leases were as follows:

	Minimum Lease Payments		
	Railcars	Vehicles & Other	Total
	(in millions)		
2013	$16	$4	$20
2014	10	2	12
2015	8	—	8
2016	8	1	9
2017	4	—	4
2018 and thereafter	9	—	9
Total	$55	$7	$62

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 2018 with maximum obligations under these leases of $21 million in 2013, $8 million in 2014, $5 million in 2015, $4 million in 2016, none in 2017, and $12 million in 2018 and thereafter. 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

At December 31, 2012, the Company had outstanding guarantees related to SEGCO's purchase of certain pollution control facilities and issuance of senior notes, as discussed in Note 4, and to certain residual values of leased assets as described above in "Operating 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, 2012, there were 1,057 current and former employees of the Company participating in the stock option program, and there were 39 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. For certain stock option awards, a change in control will provide accelerated vesting.

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.

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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	2012	2011	2010
Expected volatility	17.7 %	17.5 %	17.4 %
Expected term (in years)	5.0	5.0	5.0
Interest rate	0.9 %	2.3 %	2.4 %
Dividend yield	4.2 %	4.8 %	5.6 %
Weighted average grant-date fair value	$3.39	$3.23	$2.23

The Company's activity in the stock option program for 2012 is summarized below:

	Shares Subject to Option	Weighted Average Exercise Price
Outstanding at December 31, 2011	7,191,786	$33.63
Granted	1,099,315	44.44
Exercised	(2,226,269)	32.43
Cancelled	(4,280)	38.74
Outstanding at December 31, 2012	6,060,552	$36.02
Exercisable at December 31, 2012	3,884,089	$33.84

The number of stock options vested, and expected to vest in the future, as of December 31, 2012 was not significantly different from the number of stock options outstanding at December 31, 2012 as stated above. As of December 31, 2012, 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 $43 million and $35 million, respectively.

As of December 31, 2012, 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, 2012, 2011, and 2010, total compensation cost for stock option awards recognized in income was $4 million, $3 million, and $3 million, respectively, with the related tax benefit also recognized in income of $1 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, 2012, 2011, and 2010 was $28 million, $23 million, and $12 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $11 million, $9 million, and $4 million for the years ended December 31, 2012, 2011, and 2010, 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.

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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	2012	2011	2010
Expected volatility	16.0%	19.2%	20.7%
Expected term (in years)	3.0	3.0	3.0
Interest rate	0.4%	1.4%	1.4%
Annualized dividend rate	$1.89	$1.82	$1.75
Weighted average grant-date fair value	$41.99	$35.97	$30.13

Total unvested performance share units outstanding as of December 31, 2011 were 287,720. During 2012, 131,820 performance share units were granted, 134,054 performance share units were vested, and 4,950 performance share units were forfeited resulting in 280,536 unvested units outstanding at December 31, 2012. In January 2013, the vested performance share award units were converted into 180,997 shares outstanding at a share price of $43.05 for the three-year performance and vesting period ended December 31, 2012.
For the years ended December 31, 2012, 2011, and 2010, total compensation cost for performance share units recognized in income was $5 million, $3 million, and $1 million, respectively, with the related tax benefit also recognized in income of $2 million, $1 million, and $1 million, respectively. As of December 31, 2012, there was $5 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 $12.6 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 $117.5 million per incident for each licensed reactor it operates but not more than an aggregate of $17.5 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 $235 million per incident but not more than an aggregate of $35 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 October 29, 2013.
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 policies that currently provide decontamination, excess property insurance, and premature decommissioning coverage up to $2.25 billion for losses in excess of the $500 million primary coverage. This excess insurance is also provided by NEIL.
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 the maximum limit allowed by NEIL and has elected a 12-week deductible waiting period.

Under each of the NEIL policies, members are subject to assessments if losses each year exceed the accumulated funds available to the insurer under that policy. The current maximum annual assessments for the Company under the NEIL policies would be $42 million.

Claims resulting from terrorist acts are covered under both the ANI and NEIL policies (subject to normal policy limits). The aggregate, however, that NEIL will pay for all claims resulting from terrorist acts in any 12-month period is $3.2 billion plus such additional amounts NEIL can recover through reinsurance, indemnity, or other sources.

For all on-site property damage insurance policies for commercial nuclear power plants, the NRC requires that the proceeds of such policies shall be dedicated first for the sole purpose of placing the reactor in a safe and stable condition after an accident. Any remaining proceeds are to be applied next toward the costs of decontamination and debris removal operations ordered by the NRC, and any further remaining proceeds are to be paid either to the Company or to its debt trustees as may be appropriate under the policies and applicable trust indentures. In the event of a loss, the amount of insurance available might not be adequate to cover property damage and other expenses incurred. Uninsured losses and other expenses, to the extent not recovered from customers, would be borne by the Company and could have a material effect on the Company's financial condition and results of operations.

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

10. FAIR VALUE MEASUREMENTS

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

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

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

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As of December 31, 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:

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:				
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.

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As of December 31, 2011, 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, 2011:	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:				
Nuclear decommissioning trusts:[a]				
Domestic equity	$253	$57	$—	$310
Foreign equity	24	48	—	72
U.S. Treasury and government agency securities	17	8	—	25
Corporate bonds	—	93	—	93
Mortgage and asset backed securities	—	28	—	28
Other investments	—	11	—	11
Cash equivalents and restricted cash	209	—	—	209
Total	$503	$245	$—	$748
Liabilities:				
Energy-related derivatives	$—	$48	$—	$48
Interest rate derivatives	—	18	—	18
Total	$—	$66	$—	$66

(a) Excludes receivables related to investment income, pending investment sales, and payables related to pending investment purchases.

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 London Interbank Offered Rate (LIBOR) 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.

NOTES (continued)
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As of December 31, 2012 and 2011, 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, 2012:	(in millions)			
Nuclear decommissioning trusts:				
Equity-commingled funds	$55	None	Daily/Monthly	Daily/7 days
Trust-owned life insurance	96	None	Daily	15 days
As of December 31, 2011:				
Nuclear decommissioning trusts:				
Equity-commingled funds	$48	None	Daily/Monthly	Daily/7 days
Trust-owned life insurance	87	None	Daily	15 days
Cash equivalents and restricted cash:				
Money market funds	209	None	Daily	Not applicable

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.

As of December 31, 2012 and 2011, 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:		
2012	$6,179	$6,899
2011	$6,132	$6,874

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.

NOTES (continued)
Alabama Power Company 2012 Annual Report

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.

At December 31, 2012, 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:

	Gas	
Net Purchased mmBtu* (in millions)	Longest Hedge Date	Longest Non-Hedge Date
57	2017	—

* mmBtu – million British thermal units

For cash flow hedges, the amounts expected to be reclassified from OCI to revenue and fuel expense for the 12-month period ending December 31, 2013 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, 2012, there were no interest rate derivatives outstanding.

For the year ended December 31, 2012, the Company had realized net losses of $36 million upon termination of certain interest rate derivatives at the same time the related debt was issued. The effective portion of these losses has been deferred in OCI and is being amortized to interest expense over the life of the original interest rate derivative, reflecting the period in which the forecasted hedged transaction affects earnings.

NOTES (continued)
Alabama Power Company 2012 Annual Report

The estimated pre-tax losses that will be reclassified from OCI to interest expense for the 12-month period ending December 31, 2013 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, 2012 and 2011, 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	2012	2011	Liability Derivatives Balance Sheet Location	2012	2011
		(in millions)			(in millions)	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	$2	$—	Liabilities from risk management activities	$14	$36
	Other deferred charges and assets	3	—	Other deferred credits and liabilities	4	12
Total derivatives designated as hedging instruments for regulatory purposes		$5	$—		$18	$48
Derivatives designated as hedging instruments in cash flow hedges						
Interest rate derivatives:	Other current assets	$—	$—	Liabilities from risk management activities	$—	$18
Total		$5	$—		$18	$66

All derivative instruments are measured at fair value. See Note 10 for additional information.

At December 31, 2012 and 2011, 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	2012	2011	Unrealized Gains Balance Sheet Location	2012	2011
		(in millions)			(in millions)	
Energy-related derivatives:	Other regulatory assets, current	$(14)	$(36)	Other current liabilities	$2	$—
	Other regulatory assets, deferred	(4)	(12)	Other regulatory liabilities, deferred	3	—
Total energy-related derivative gains (losses)		$(18)	$(48)		$5	$—

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NOTES (continued)
Alabama Power Company 2012 Annual Report

For the years ended December 31, 2012, 2011, and 2010, 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	2012	2011	2010	Statements of Income Location	2012	2011	2010
	(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, 2012, 2011, and 2010, 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, 2012, the fair value of derivative liabilities with contingent features was $2 million.

At December 31, 2012, 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 $15 million. 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.

NOTES (continued)
Alabama Power Company 2012 Annual Report

12. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)
Summarized quarterly financial information for 2012 and 2011 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred and Preference Stock
	(in millions)		
March 2012	$1,216	$291	$126
June 2012	1,377	390	185
September 2012	1,637	544	280
December 2012	1,290	271	113
March 2011	$1,320	$329	$152
June 2011	1,440	404	190
September 2011	1,671	523	264
December 2011	1,271	258	102

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

SELECTED FINANCIAL AND OPERATING DATA 2008-2012
Alabama Power Company 2012 Annual Report

	2012	2011	2010	2009	2008
Operating Revenues (in millions)	$5,520	$5,702	$5,976	$5,529	$6,077
Net Income After Dividends on Preferred and Preference Stock (in millions)	$704	$708	$707	$670	$616
Cash Dividends on Common Stock (in millions)	$684	$774	$586	$523	$491
Return on Average Common Equity (percent)	13.10	13.19	13.31	13.27	13.30
Total Assets (in millions)	$18,712	$18,477	$17,994	$17,524	$16,536
Gross Property Additions (in millions)	$940	$1,016	$956	$1,323	$1,533
Capitalization (in millions):					
Common stock equity	$5,398	$5,342	$5,393	$5,237	$4,854
Preference stock	343	343	343	343	343
Redeemable preferred stock	342	342	342	342	342
Long-term debt	5,929	5,632	5,987	6,082	5,605
Total (excluding amounts due within one year)	$12,012	$11,659	$12,065	$12,004	$11,144
Capitalization Ratios (percent):					
Common stock equity	44.9	45.8	44.7	43.6	43.6
Preference stock	2.9	2.9	2.9	2.9	3.1
Redeemable preferred stock	2.8	2.9	2.8	2.8	3.0
Long-term debt	49.4	48.4	49.6	50.7	50.3
Total (excluding amounts due within one year)	100.0	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	1,237,730	1,231,574	1,235,128	1,229,134	1,220,046
Commercial	196,177	196,270	197,336	198,642	211,119
Industrial	5,839	5,844	5,770	5,912	5,906
Other	748	746	782	780	775
Total	1,440,494	1,434,434	1,439,016	1,434,468	1,437,846
Employees (year-end)	6,778	6,632	6,552	6,842	6,997

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SELECTED FINANCIAL AND OPERATING DATA 2008-2012 (continued)
Alabama Power Company 2012 Annual Report

	2012	2011	2010	2009	2008
Operating Revenues (in millions):					
Residential	$2,068	$2,144	$2,283	$1,962	$1,998
Commercial	1,491	1,495	1,535	1,430	1,459
Industrial	1,346	1,306	1,231	1,080	1,381
Other	28	27	27	25	24
Total retail	4,933	4,972	5,076	4,497	4,862
Wholesale — non-affiliates	277	287	465	620	712
Wholesale — affiliates	111	244	236	237	308
Total revenues from sales of electricity	5,321	5,503	5,777	5,354	5,882
Other revenues	199	199	199	175	195
Total	$5,520	$5,702	$5,976	$5,529	$6,077
Kilowatt-Hour Sales (in millions):					
Residential	17,612	18,650	20,417	18,071	18,380
Commercial	13,963	14,173	14,719	14,186	14,551
Industrial	22,158	21,666	20,622	18,555	22,075
Other	214	214	216	218	201
Total retail	53,947	54,703	55,974	51,030	55,207
Wholesale — non-affiliates	4,196	4,330	8,655	14,317	15,204
Wholesale — affiliates	4,279	7,211	6,074	6,473	5,256
Total	62,422	66,244	70,703	71,820	75,667
Average Revenue Per Kilowatt-Hour (cents):					
Residential	11.74	11.50	11.18	10.86	10.87
Commercial	10.68	10.55	10.43	10.08	10.03
Industrial	6.07	6.03	5.97	5.82	6.26
Total retail	9.14	9.09	9.07	8.81	8.81
Wholesale	4.58	4.60	4.76	4.12	4.99
Total sales	8.52	8.31	8.17	7.45	7.77
Residential Average Annual Kilowatt-Hour Use Per Customer	14,252	15,138	16,570	14,716	15,162
Residential Average Annual Revenue Per Customer	$1,674	$1,740	$1,853	$1,597	$1,648
Plant Nameplate Capacity Ratings (year-end) (megawatts)	12,222	12,222	12,222	12,222	12,222
Maximum Peak-Hour Demand (megawatts):					
Winter	10,285	11,553	11,349	10,701	10,747
Summer	11,096	11,500	11,488	10,870	11,518
Annual Load Factor (percent)	61.3	60.6	62.6	59.8	60.9
Plant Availability (percent)*:					
Fossil-steam	88.6	88.7	92.9	88.5	90.1
Nuclear	94.5	94.7	88.4	93.3	94.1
Source of Energy Supply (percent):					
Coal	48.2	52.5	56.6	53.4	58.5

Nuclear	22.6	20.8	17.7	18.6	17.8
Hydro	4.1	4.6	5.0	7.9	2.9
Gas	16.8	15.3	14.0	11.8	9.2
Purchased power —					
From non-affiliates	2.0	0.9	1.6	2.0	2.9
From affiliates	6.3	5.9	5.1	6.3	8.7
Total	100.0	100.0	100.0	100.0	100.0

* Beginning in 2012, plant availability is calculated as a weighted equivalent availability.

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GEORGIA POWER COMPANY
FINANCIAL SECTION

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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Georgia Power Company 2012 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 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, 2012.

/s/ W. Paul Bowers
W. Paul Bowers
President and Chief Executive Officer
/s/ Ronnie R. Labrato
Ronnie R. Labrato
Executive Vice President, Chief Financial Officer, and Treasurer
February 27, 2013

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, 2012 and 2011, 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, 2012. 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-231 to II-280) present fairly, in all material respects, the financial position of Georgia Power Company as of December 31, 2012 and 2011, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 27, 2013

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Georgia Power Company 2012 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. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future. In 2010, the Georgia Public Service Commission (PSC) approved an Alternate Rate Plan for the years 2011 through 2013 (2010 ARP), including base rate increases of approximately $562 million, $20 million, $122 million, and $74 million effective January 1, 2011, January 1, 2012, April 1, 2012, and January 1, 2013, respectively. The Company is scheduled to file its next base rate case by July 1, 2013.
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 2012 fossil/hydro Peak Season EFOR did not meet the target due to an unplanned outage at Plant Bowen. 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 2012 performance exceeded 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 2012 results compared to its targets for some of these key indicators are reflected in the following chart:

Key Performance Indicator	2012 Target Performance	2012 Actual Performance
Customer Satisfaction	Top quartile in customer surveys	Top quartile
Peak Season EFOR — fossil/hydro	4.99% or less	5.31%
Net Income After Dividends on Preferred and Preference Stock	$1.14 billion	$1.17 billion

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance. The performance achieved in 2012 reflects the continued emphasis that management places on these indicators, as well as the commitment shown by employees in achieving or exceeding management's expectations.
Earnings

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 under the 2010 ARP. These increases were partially offset by lower operating revenues as a result of 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).

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Georgia Power Company 2012 Annual Report

The Company's 2011 net income after dividends on preferred and preference stock totaled $1.1 billion representing a $195 million, or 20.5%, increase over the previous year. The increase was due primarily to increases in retail base revenues, effective January 1, 2011, as authorized under the 2010 ARP and the financing costs associated with the construction of Plant Vogtle Units 3 and 4, collected through the Nuclear Construction Cost Recovery (NCCR) tariff, partially offset by closer to normal weather in 2011 when compared to 2010, higher non-fuel operating expenses, lower AFUDC equity, and higher income taxes. The increase was also due to a reduction in interest expense arising from the settlement of tax litigation with the Georgia DOR, partially offset by a decrease in the amortization of the regulatory liability related to other cost of removal obligations.

RESULTS OF OPERATIONS

A condensed income statement for the Company follows:

	Amount	Increase (Decrease) from Prior Year	
	2012	2012	2011
	(in millions)		
Operating revenues	$7,998	$(802)	$451
Fuel	2,051	(738)	(313)
Purchased power	981	(122)	157
Other operations and maintenance	1,644	(133)	43
Depreciation and amortization	745	30	157
Taxes other than income taxes	374	5	25
Total operating expenses	5,795	(958)	69
Operating income	2,203	156	382
Allowance for equity funds used during construction	53	(43)	(51)
Interest expense, net of amounts capitalized	366	23	(32)
Other income (expense), net	(17)	(4)	4
Income taxes	688	63	172
Net income	1,185	23	195
Dividends on preferred and preference stock	17	—	—
Net income after dividends on preferred and preference stock	$1,168	$23	$195

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Georgia Power Company 2012 Annual Report

Operating Revenues
Details of operating revenues were as follows:

	Amount 2012	2011
	(in millions)	
Retail — prior year	$8,099	$7,608
Estimated change in —		
Rates and pricing	166	703
Sales growth (decline)	(26)	(9)
Weather	(147)	(105)
Fuel cost recovery	(730)	(98)
Retail — current year	7,362	8,099
Wholesale revenues —		
Non-affiliates	281	341
Affiliates	20	32
Total wholesale revenues	301	373
Other operating revenues	335	328
Total operating revenues	$7,998	$8,800
Percent change	(9.1)%	5.4%

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, partially offset by base tariff increases effective April 1, 2012 related to placing Plant McDonough-Atkinson Units 4 and 5 in service, as well as for the collection of financing costs associated with 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, and 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 continues to impact residential, commercial, and industrial base revenues.

Retail base revenues of $4.8 billion in 2011 increased by $588 million, or 14.0%, from 2010 primarily due to increases authorized under the 2010 ARP, which became effective January 1, 2011. This increase was partially offset by closer to normal weather in 2011 compared to 2010. The increase in base revenues also included the collection of financing costs associated with the construction of Plant Vogtle Units 3 and 4 through the NCCR tariff effective January 1, 2011. See "Allowance for Funds Used During Construction Equity," "Interest Expense, Net of Amounts Capitalized," and FUTURE EARNINGS POTENTIAL – "PSC Matters – Nuclear Construction" herein for additional information. In 2011, residential base revenues increased $225 million, or 11.8%, commercial base revenues increased $236 million, or 14.1%, and industrial base revenues increased $118 million, or 21.4%, compared to 2010.

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, including the fuel component of purchased power, 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 2012 Annual Report

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

	2012	2011	2010
	(in millions)		
Other power sales —			
Capacity and other	$177	$177	$155
Energy	104	164	194
Total	281	341	349
Unit power sales —			
Capacity	—	—	18
Energy	—	—	13
Total	—	—	31
Total non-affiliated	$281	$341	$380

Wholesale revenues from sales to non-affiliates consist of power purchase agreements (PPA) and short-term opportunity sales, and, in 2010, from a unit power sales agreement. 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 decreased $60 million, or 17.6%, in 2012 and $8 million, or 2.3%, in 2011. 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. The decrease in 2011 was primarily due to a 16.3% decrease in KWH sales reflecting lower demand resulting from both more normal weather in 2011 compared to 2010 and the lower market costs of available energy compared to Company-owned generation.

Wholesale revenues from sales to affiliated companies will vary from year to year depending on demand and the availability and cost of generating resources at each company. These affiliated 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. In 2012 and 2011, wholesale revenues from sales to affiliates decreased $12 million and $21 million from the prior year, respectively, due to decreases of 4.2% and 37.4%, respectively, 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 $7 million, or 2.1%, in 2012 from the prior year primarily due to higher revenues from outdoor lighting and pole attachments. Other operating revenues increased $20 million, or 6.5%, in 2011 from the prior year primarily due to new contracts that replaced the transmission component of a unit power sales agreement that expired in 2010 and increased usage of the Company's transmission system by non-affiliate companies.

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Georgia Power Company 2012 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 2012 and the percent change by year were as follows:

	Total KWHs 2012 (in billions)	Total KWH Percent Change 2012	Total KWH Percent Change 2011	Weather-Adjusted Percent Change 2012	Weather-Adjusted Percent Change 2011
Residential	25.7	(5.4)%	(7.5)%	0.3%	(0.4)%
Commercial	32.3	(1.9)	(2.8)	(0.6)	(0.4)
Industrial	23.1	(1.8)	1.3	(1.2)	1.6
Other	0.7	(2.5)	(0.9)	(2.0)	(0.6)
Total retail	81.8	(3.0)	(3.3)	(0.5)%	0.2%
Wholesale					
Non-affiliates	2.9	(24.9)	(16.3)		
Affiliates	0.6	(4.2)	(37.4)		
Total wholesale	3.5	(22.0)	(20.0)		
Total energy sales	85.3	(4.0)%	(4.3)%		

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 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.

In 2011, residential and commercial KWH sales decreased compared to 2010 primarily due to closer to normal weather in 2011 compared to 2010. Industrial KWH sales increased in 2011 compared to 2010 primarily due to increased demand in the primary metals sector.

See "Operating Revenues" above for a discussion of significant changes in wholesale sales to non-affiliates and affiliated companies.

Fuel and Purchased Power Expenses

Fuel costs constitute 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.

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

	2012	2011	2010
Total generation (billions of KWHs)	59.8	65.5	75.3
Total purchased power (billions of KWHs)	28.7	26.8	21.7
Sources of generation (percent) -			
Coal	39	62	67
Nuclear	27	23	21
Gas	33	13	10
Hydro	1	2	2
Cost of fuel, generated (cents per net KWH) -			
Coal	4.63	4.70	4.53
Nuclear	0.87	0.78	0.66
Gas	3.02	4.92	5.75
Average cost of fuel, generated (cents per net KWH)	3.07	3.80	3.82
Average cost of purchased power (cents per net KWH) *	4.24	5.38	5.64

* 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 $3.0 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 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 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 expenses were $3.9 billion in 2011, a decrease of $156 million, or 3.9%, compared to 2010. The decrease was primarily due to an $86 million decrease in the average cost of purchased power and gas, partially offset by increases in the average cost of coal and nuclear fuel. The decrease was also due to a $358 million decrease related to fewer KWHs generated as a result of lower customer demand, partially offset by a $288 million increase in KWHs purchased as the market cost of energy was lower than the additional Company-owned generation available.

From an overall global market perspective, coal prices decreased from levels experienced in 2011 due to lower demand. In the U.S., this decrease was due primarily to relatively lower domestic natural gas prices that contributed to displacement of coal generation by natural gas-fueled generating units. Lower domestic natural gas prices in 2012 were driven by continued robust supplies, including production from shale gas, and only modest increases in overall U.S. consumption.

Uranium prices began to decrease during the second half of 2012 as extended reactor shutdowns in Europe and Asia caused global demand for uranium to drop below the level of previous years, while production increased. Changes in the cost of fuel for nuclear generation tend to lag behind changes in uranium market prices. Even though uranium prices decreased slightly during 2012, the cost of fuel for nuclear generation increased in 2012, reflecting the higher uranium prices from previous years when the uranium was purchased.

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 $2.1 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. Fuel expenses were $2.8 billion in 2011, a decrease of $313 million, or 10.1%, compared to 2010. The decrease was primarily due to a 14.4% decrease in the average cost of gas and a 12.7% decrease in KWHs generated, partially offset by 18.2% and 3.8% increases in the average cost of nuclear fuel and coal, respectively.

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Purchased Power - Non-Affiliates
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. Purchased power expense from non-affiliates was $390 million in 2011, an increase of $22 million, or 6.0%, compared to 2010. The increase was primarily due to a 13.1% increase in the volume of KWHs purchased as the market cost of available energy was lower than the additional Company-owned generation, partially offset by a 4.2% decrease in the average cost per KWH purchased primarily due to lower natural gas prices.
Energy purchases from non-affiliates will vary depending on the market prices of wholesale energy as compared to the cost of the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation.
Purchased Power - Affiliates
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. Purchased power expense from affiliates was $713 million in 2011, an increase of $135 million, or 23.4%, compared to 2010. The increase was primarily due to a 26.8% increase in the volume of KWHs purchased as the cost of available energy was lower than the cost of Company-owned generation available, partially offset by a 2.9% decrease in the average cost per KWH purchased, reflecting lower natural gas prices.
Energy purchases from affiliates will vary depending on the demand and the availability and cost of generating resources at each company within the Southern Company system. These purchases are made in accordance with the IIC or other contractual agreements, all as approved by the FERC.
Other Operations and Maintenance Expenses
In 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 change in the customer deposit policy, partially offset by a net increase in pension and other employee benefit-related expenses of $14 million.
In 2011, other operations and maintenance expenses increased $43 million, or 2.5%, compared to 2010. The increase was due to a $22 million increase in customer assistance expenses related to new demand side management programs in 2011, an $8 million increase in uncollectible account expense as a result of higher revenues and economic conditions, and a $6 million increase in workers compensation expense resulting from a higher volume of claims.
Depreciation and Amortization
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.
Depreciation and amortization increased $157 million, or 28.1%, in 2011 compared to 2010. The increase was primarily due to a $142 million decrease in the amortization of the regulatory liability related to other cost of removal obligations as authorized by the Georgia PSC. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Rate Plans" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Rate Plans" for additional information. See Note 1 to the financial statements under "Depreciation and Amortization" for additional information.

Taxes Other Than Income 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.

In 2011, taxes other than income taxes increased $25 million, or 7.3%, compared to 2010 primarily due to a $17 million increase in property taxes and a $9 million increase in municipal franchise fees related to an increase in retail revenues.

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Allowance for Funds Used During Construction Equity
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.
AFUDC equity decreased $51 million, or 34.7%, in 2011 compared to the prior year primarily due to the inclusion of construction costs for Plant Vogtle Units 3 and 4 in rate base effective January 1, 2011 in accordance with the Georgia Nuclear Energy Financing Act and a Georgia PSC order. This action reduced the amount of AFUDC capitalized with an offsetting increase in operating revenues through the NCCR tariff. See Note 3 to the financial statements under "Retail Regulatory Matters – Nuclear Construction."
Interest Expense, Net of Amounts Capitalized
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.
In 2011, interest expense, net of amounts capitalized decreased $32 million, or 8.5%, from the prior year primarily due to a reduction of $23 million in interest expense related to the settlement of litigation with the Georgia DOR and lower interest expense on existing variable rate pollution control revenue bonds, partially offset by a reduction in AFUDC debt due to the inclusion of construction costs for Plant Vogtle Units 3 and 4 in rate base as discussed previously.
Income Taxes
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.
Income taxes increased $172 million, or 38.0%, in 2011 compared to the prior year primarily due to higher pre-tax earnings, a decrease in non-taxable AFUDC equity, and the recognition in 2010 of certain 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. 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 neighboring 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 economic conditions impact sales for the Company,

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and 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 2012, the Company's generating capacity increased 1,680 megawatts (MWs), net of retirements of 284 MWs, due to the completion of Plant McDonough-Atkinson Units 5 and 6. New generating capacity is 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

In 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including the Company, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. The EPA alleged NSR violations at three coal-fired generating facilities operated by the Company and five coal-fired generating facilities operated by Alabama Power Company (Alabama Power). The civil action sought penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. The case against the Company was administratively closed in 2001 and has not been reopened.

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.

Climate Change Litigation

Kivalina Case

In 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs allege that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that some of the defendants (including Southern Company) acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. In 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case. On September 21, 2012, the U.S. Court of Appeals for the Ninth Circuit upheld the U.S. District Court for the Northern District of California's dismissal of the case. On November 27, 2012, the U.S. Court of Appeals for the Ninth Circuit denied the plaintiffs' request for review of the decision. On February 25, 2013, the plaintiffs filed a petition for writ of certiorari with the U.S. Supreme Court. Southern Company believes that these claims are without merit. The ultimate outcome of this matter cannot be determined at this time.

Hurricane Katrina Case

In 2005, immediately following Hurricane Katrina, a lawsuit was filed in the U.S. District Court for the Southern District of Mississippi by Ned Comer on behalf of Mississippi residents seeking recovery for property damage and personal injuries caused by Hurricane Katrina. In 2006, the plaintiffs amended the complaint to include Southern Company and many other electric utilities, oil companies, chemical companies, and coal producers. The plaintiffs allege that the defendants contributed to climate change, which contributed to the intensity of Hurricane Katrina. In 2007, the U.S. District Court for the Southern District of Mississippi dismissed the case. On appeal to the U.S. Court of Appeals for the Fifth Circuit, a three-judge panel reversed the U.S.

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District Court for the Southern District of Mississippi, holding that the case could proceed, but, on rehearing, the full U.S. Court of Appeals for the Fifth Circuit dismissed the plaintiffs' appeal, resulting in reinstatement of the decision of the U.S. District Court for the Southern District of Mississippi in favor of the defendants. In May 2011, the plaintiffs filed an amended version of their class action complaint, arguing that the earlier dismissal was on procedural grounds and under Mississippi law the plaintiffs have a right to re-file. The amended complaint was also filed against numerous chemical, coal, oil, and utility companies, including the Company. On March 20, 2012, the U.S. District Court for the Southern District of Mississippi dismissed the plaintiffs' amended complaint. On April 16, 2012, the plaintiffs appealed the case to the U.S. Court of Appeals for the Fifth Circuit. The Company believes that these claims are without merit. 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 2012, the Company had invested approximately $4.0 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $152 million, $113 million, and $217 million in 2012, 2011, and 2010, respectively. The Company expects that capital expenditures to comply with existing statutes and regulations, including capital expenditures and compliance costs associated with the EPA's final Mercury and Air Toxics Standards (MATS) rule, will be a total of approximately $1.3 billion from 2013 through 2015, with annual totals of approximately $476 million, $441 million, and $392 million for 2013, 2014, and 2015, respectively.

The Company continues to monitor the development of the EPA's proposed water and coal combustion byproducts rules and to evaluate compliance options. Based on its preliminary analysis and an assumption that coal combustion byproducts 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 2013 through 2015. The ultimate capital expenditures and compliance costs with respect to these proposed rules, including additional expenditures required after 2015, 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 Byproducts" 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. The impact of SEGCO's ultimate compliance strategy on such PPA costs cannot be determined at this time; however, if such 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 byproducts, 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.

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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 $3.6 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 air quality standard. In 2008, the EPA adopted a more stringent eight-hour ozone National Ambient Air Quality Standard, which it began to implement in September 2011. On May 21, 2012, the EPA published its final determination of nonattainment areas based on the 2008 eight-hour ozone air quality standards. 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 National Ambient Air Quality Standards. Redesignation requests for nonattainment areas 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 National Ambient Air Quality Standard for sulfur dioxide (SO_2), including the establishment of a new one-hour standard, became effective in 2010 (SO_2 Rule). The EPA plans to issue area designations under this new standard in June 2013, and areas within the Company's service territory could ultimately be designated as nonattainment. Implementation of the revised SO_2 standard could require additional reductions in SO_2 emissions and increased compliance and operational costs.

Revisions to the National Ambient Air Quality Standard for nitrogen dioxide (NO_2), which established a new one-hour standard, became effective in 2010. On February 29, 2012, the new NO_2 standard became effective. The EPA designated the entire country as "unclassifiable/attainment" under the new standard, with no nonattainment areas designated. However, the new NO_2 standard could result in significant additional compliance and operational costs for units that require new source permitting.

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 August 2011, the EPA adopted the Cross State Air Pollution Rule (CSAPR) to replace CAIR effective January 1, 2012. However, in December 2011, the U.S. Court of Appeals for the District of Columbia Circuit stayed the rule and, on August 21, 2012, vacated CSAPR in its entirety and directed the EPA to continue to administer CAIR pending the EPA's development of a valid replacement. On January 24, 2013, the U.S. Court of Appeals for the District of Columbia Circuit denied requests by the EPA and other parties for rehearing.

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 (BART) 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 2005, the EPA determined that compliance with CAIR satisfies BART obligations under CAVR, but, on June 7, 2012, the EPA issued a final rule replacing CAIR with CSAPR as an alternative means of satisfying BART obligations. The vacatur of CSAPR creates additional uncertainty with respect to whether additional controls may be required for CAVR and BART compliance.

On February 16, 2012, the EPA published the final 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, unless a one-year compliance extension is granted by the state or local

air permitting agency.
Numerous petitions for administrative reconsideration of the MATS rule, including a petition by the Company, have been filed with the EPA. On November 30, 2012, the EPA proposed a reconsideration of certain new source and startup/shutdown issues. The EPA plans to complete its reconsideration rulemaking by March 2013. Challenges to the final rule have also been filed in the U.S. District Court for the District of Columbia by numerous states, environmental organizations, industry groups, and others.
On August 29, 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.

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On January 31, 2013, the EPA published the final Industrial Boiler Maximum Achievable Control Technology (IB MACT) rule establishing emissions limits and/or work practice standards for various hazardous air pollutants emitted from industrial boilers, including biomass boilers and start-up boilers. Compliance for existing sources will be required by early 2016. Compliance for new sources will begin upon startup. The Company is evaluating the impact of this final rule and other environmental regulations on the possible conversion of Plant Mitchell Unit 3 from coal to biomass.

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. If finalized as proposed, this new requirement could result in significant additional compliance and operational costs.

The Company has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the existing and new environmental requirements discussed above. The impacts of the eight-hour ozone, fine particulate matter, SO_2 and NO_2 standards, CAIR and any future replacement rule, CAVR, the MATS rule, the NSPS for CTs, the IB MACT rule, 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 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 December 31, 2015. The State of Georgia also adopted a companion rule that requires a 95% reduction in SO2 emissions from the controlled units on the same or similar timetable. Through December 31, 2012, the Company had installed the required controls on 11 of its largest coal-fired generating units and is in the process of installing the required controls on two additional units. On February 21, 2013, the State of Georgia released proposed revisions for both the Multi-Pollutant Rule and the SO_2 Rule revising the compliance dates for those units yet to be controlled to make them consistent with the April 2015 compliance date for the MATS rule. According to the State of Georgia, the proposed revisions would also allow the units at Plant Yates to use natural gas as the primary fuel as an alternative to installing controls under the Multi-Pollutant Rule. The revisions to the Multi-Pollutant Rule and the SO_2 Rule are expected to be finalized in April 2013.

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

Water Quality

In April 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 has entered into an amended settlement agreement to extend the deadline for issuing a final rule until June 27, 2013. If finalized as proposed, some of the Company's facilities may be subject to 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. The ultimate outcome of this rulemaking will depend on the final rule and the outcome of any legal challenges and cannot be determined at this time.

The EPA has announced its determination that revision of the current effluent guidelines for steam electric power plants is warranted and has stated that it intends to propose such revisions by April 2013 and finalize the revisions by May 2014. New advanced wastewater treatment requirements are expected and may result in the installation of additional controls on certain of the Company's facilities, which could result in significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. The impact of the revised guidelines will depend on the specific technology requirements of the final rule and, therefore, cannot be determined at this time.

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Coal Combustion Byproducts

The Company currently operates 11 electric generating plants with on-site coal combustion byproducts, including coal ash and gypsum storage facilities. In addition to on-site storage, the Company also sells a portion of its coal combustion byproducts to third parties for beneficial reuse. Historically, individual states have regulated coal combustion byproducts and the States of Georgia and Alabama have their own separate regulatory parameters. 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 byproducts, 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 byproducts: 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 byproducts 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 byproducts.

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 byproducts could have a material impact on the generation, management, beneficial use, and disposal of such byproducts. 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. 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 April 13, 2012, the EPA published proposed regulations to establish standards of performance for greenhouse gas emissions from new fossil fuel steam electric generating units. The EPA has also announced plans to develop federal guidelines for states to establish greenhouse gas emissions performance standards for existing sources. The impact of this rulemaking will depend on the scope and specific requirements of the final rule and the outcome of any legal challenges and, therefore, cannot be determined at this time.

Although the outcome of federal, state, and international initiatives 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 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.

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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 reported 2011 greenhouse gas emissions of approximately 47 million metric tons of carbon dioxide equivalent. The preliminary estimate of the Company's 2012 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, which is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units.

PSC Matters

Rate Plans

The economic recession significantly reduced the Company's revenues upon which retail rates were set under the 2007 Retail Rate Plan. In 2009, despite stringent efforts to reduce expenses, the Company's projected retail return on common equity (ROE) for both 2009 and 2010 was below 10.25%. However, in lieu of a full base rate case to increase customer rates as allowed under the 2007 Retail Rate Plan, in 2009, the Georgia PSC approved the Company's request for an accounting order. Under the terms of the accounting order, the Company could amortize up to $108 million of the regulatory liability related to other cost of removal obligations in 2009 and up to $216 million in 2010, limited to the amount needed to earn no more than a 9.75% and 10.15% retail ROE in 2009 and 2010, respectively. For the years ended December 31, 2009 and 2010, the Company amortized $41 million and $174 million, respectively, of the regulatory liability related to other cost of removal obligations.

In 2010, the Georgia PSC approved the 2010 ARP, which became effective January 1, 2011. The terms of the 2010 ARP reflect a settlement agreement among the Company, the Georgia PSC Public Interest Advocacy Staff, and eight other intervenors. Under the terms of the 2010 ARP, the Company is amortizing approximately $92 million of its remaining regulatory liability related to other cost of removal obligations over the three years ending December 31, 2013.

Also under the terms of the 2010 ARP, effective January 1, 2011, the Company increased its (1) traditional base tariff rates by approximately $347 million; (2) Demand-Side Management (DSM) tariff rates by approximately $31 million; (3) ECCR tariff rate by approximately $168 million; and (4) Municipal Franchise Fee (MFF) tariff rate by approximately $16 million, for a total increase in base revenues of approximately $562 million.

Under the 2010 ARP, the following additional base rate adjustments have been made to the Company's tariffs in 2012 and 2013:

- Effective January 1, 2012 and 2013, the DSM tariffs increased by $17 million and $14 million, respectively;
- Effective April 1, 2012 and January 1, 2013, the traditional base tariffs increased by an estimated $122 million and $58 million, respectively, to recover the revenue requirements for Plant McDonough-Atkinson Units 4, 5, and 6 for the period through December 31, 2013; and
- The MFF tariff increased consistently with the adjustments above, as well as those related to the interim fuel rider (IFR) and NCCR tariff adjustments described herein under "Fuel Cost Recovery" and "Nuclear Construction."

Under the 2010 ARP, the Company's allowed retail ROE is set at 11.15%, and earnings will be evaluated against a retail ROE range of 10.25% to 12.25%. Two-thirds of any earnings above 12.25% will be directly refunded to customers, with the remaining one-third retained by the Company. There were no refunds related to earnings for 2011 or 2012. The Company is required to file a general base rate case by July 1, 2013, in response to which the Georgia PSC would be expected to determine whether the 2010 ARP should be continued, modified, or discontinued.

Integrated Resource Plans

See "Environmental Matters – Environmental Statutes and Regulations – Air Quality," "– Water Quality," and "– Coal Combustion Byproducts" 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 guidelines for steam electric power plants, and additional regulation of coal combustion byproducts; 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 2010 ARP.

On March 20, 2012, the Georgia PSC approved the Company's request to decertify and retire Plant Branch Units 1 and 2 as of December 31, 2013 and October 31, 2013, the compliance dates for the respective units under the Georgia Multi-Pollutant Rule, and an oil-fired unit at Plant Mitchell as of March 26, 2012, as requested in the 2011 IRP. The Georgia PSC also approved three PPAs totaling 998 MWs with Southern Power for capacity and energy that will commence in 2015 and end in 2030. On November 21, 2012, the FERC accepted the PPAs.

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Separately, on March 20, 2012, the Georgia PSC certified 495 MWs of wholesale capacity to be returned to retail service in 2015 and 2016 under a 2010 agreement, subject to the decertification of any related generating units including 243 MWs of the 16 units described below.

Separately, on October 16, 2012, the Georgia PSC approved a 50 MW PPA with a small power production facility (80 MWs or less) that is a qualifying facility under the Public Utility Regulatory Policies Act of 1978 for capacity and energy that will commence in 2015 and end in 2035.

In addition, on November 20, 2012, the Georgia PSC approved the Company's advanced solar initiative. The Company may acquire up to 210 MWs of additional solar capacity over a three-year period through long-term contracts.

On January 31, 2013, the Company filed its triennial IRP (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.

The Company requested the decertification of Plant Boulevard Units 2 and 3 (28 MWs) upon approval of the 2013 IRP and the decertification of Plant Bowen Unit 6 (32 MWs) by April 16, 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 retired by April 16, 2015, the compliance date of the MATS rule. The Company has also requested a revision to the decertification date of Plant Branch Unit 1 from December 31, 2013 to April 16, 2015. To allow for necessary transmission reliability improvements, the Company expects to seek a one-year extension of the MATS rule compliance date for Plant Kraft Units 1 through 4 (316 MWs) and to retire these units by April 16, 2016.

The filing also included the Company's request to switch the primary fuel source for Plant Yates Units 6 and 7 from coal to natural gas. Additionally, the Company plans to switch the primary fuel source for Plant McIntosh Unit 1 from Central Appalachian coal to Powder River Basin (PRB) coal following further evaluation, including a successful test burn of the PRB fuel.

Under the terms of the 2010 ARP, any costs associated with changes to the Company's approved environmental operating or capital budgets resulting from new or revised environmental regulations through 2013 that are approved by the Georgia PSC in connection with an updated IRP will be deferred as a regulatory asset to be recovered over a time period deemed appropriate by the Georgia PSC. In connection with the retirement decisions, the Company reclassified the retail portion of the net carrying value of Plant Branch Units 1 through 4 from plant in service, net of depreciation, to other utility plant, net. The Company is continuing to depreciate these units using the current composite straight-line rates previously approved by the Georgia PSC. Upon actual retirement, the Georgia PSC approved the continued deferral and amortization of the remaining net carrying values for Plant Branch Units 1 and 2 in its order for the 2011 IRP and the Company has requested similar treatment for Plant Branch Units 3 and 4 in the 2013 IRP. The Company also reclassified the construction work in progress (CWIP) balances totaling $65 million related to environmental controls for Plant Branch Units 1 through 4 and Plant Yates Units 6 and 7 that will not be completed as a result of the retirement decisions to regulatory assets and ceased accruing AFUDC. The Georgia PSC approved a three-year amortization period beginning January 2014 for the $13 million balance relating to Plant Branch Units 1 and 2 in its order for the 2011 IRP and the Company has requested similar treatment for the balances related to Plant Branch Units 3 and 4 and Plant Yates Units 6 and 7 in the 2013 IRP. The Company has also requested that the Georgia PSC approve the deferral of the costs associated with material and supplies remaining at the unit retirement dates to a regulatory asset, to be amortized over a time period deemed appropriate by the Georgia PSC. As a result of this regulatory treatment, the decertification of these units is not expected to have a material impact on the Company's financial statements. The Georgia PSC is scheduled to vote on the 2013 IRP by July 2013.

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. In addition, the Georgia PSC has authorized an IFR, which allows the Company to adjust its fuel cost recovery rates prior to the next fuel case if the under or over recovered fuel balance exceeds $215 million through February 2013 and $200 million thereafter. 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 10 to the financial statements under "Energy-Related Derivatives" for additional information. The Company expects to file its next fuel case by March 1, 2014.

The Company's over recovered fuel balance totaled approximately $230 million at December 31, 2012 and is included in current liabilities and other deferred credits and liabilities.

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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, 2012, the balance in the regulatory asset related to storm damage was $38 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 and, at certain stages of the work, cancellation fees to the Contractor. 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 Georgia PSC originally certified construction costs of $6.4 billion to place Plant Vogtle Units 3 and 4 into service in April 2016 and April 2017, respectively, and approved inclusion of the related CWIP accounts in rate base. Also in 2009, the State of Georgia enacted the Georgia Nuclear Energy Financing Act, which allows the Company to recover financing costs for nuclear construction projects through annual adjustments to an NCCR tariff by including the related CWIP accounts in rate base during the construction period. With respect to Plant Vogtle Units 3 and 4, this legislation allowed the Company, beginning in 2011, to recover an estimated $1.7 billion of related financing costs during the construction period. As a result, in 2009, the Georgia PSC also revised the certified in-service capital cost to approximately $4.4 billion.

The Georgia PSC approved increases to the NCCR tariff of approximately $223 million, $35 million, and $50 million, effective January 1, 2011, 2012, and 2013, 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, 2012, approximately $55 million of these 2009 and 2010 costs remained unamortized in CWIP. At December 31, 2012, the Company's

CWIP balance for Plant Vogtle Units 3 and 4 totaled $2.3 billion.

In 2009, the 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) on February 10, 2012. Receipt of the COLs allowed full construction to begin.

On February 16, 2012, separate groups of petitioners filed petitions in the U.S. Court of Appeals for the District of Columbia Circuit seeking judicial review of the NRC's issuance of the COLs and certification of the DCD. These petitions were consolidated on April 3, 2012. On April 18, 2012, another group of petitioners filed a motion to stay the effectiveness of the COLs with the U.S. District Court for the District of Columbia. On July 11, 2012, the U.S. Court of Appeals for the District of Columbia Circuit denied the petitioners' motion to stay the effectiveness of the COLs. The Company has intervened in, and

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intends to vigorously contest, these petitions. Additional technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4, at the federal and state level, are expected as construction proceeds.

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. On February 19, 2013, the Georgia PSC voted to approve the Company's seventh VCM report, including construction capital costs incurred through June 30, 2012 of approximately $2.0 billion. The Company's eighth VCM report requests approval for an additional $0.2 billion of construction capital costs incurred through December 31, 2012. 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 eighth VCM also requests an amendment to the certificate to increase the estimated in-service capital cost of Plant Vogtle Units 3 and 4 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. Associated financing costs during the construction period are estimated to total approximately $2.0 billion.

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 Contractor has claimed that its estimated adjustment attributable to the Company (based on the Company's ownership interest) is approximately $425 million (in 2008 dollars) with respect to these issues. 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. On November 1, 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 on November 1, 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. While litigation has commenced and the Company intends to vigorously defend its positions, the Company 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.

In addition, there are processes in place that are designed to assure compliance with the requirements specified in the DCD and the COLs, including rigorous inspections by Southern Nuclear and the NRC that occur throughout construction. During the fourth quarter 2012, certain details of the rebar design for the Plant Vogtle Unit 3 nuclear island were evaluated for consistency with the DCD and a few non-safety-related deviations were identified. On January 15, 2013 and January 18, 2013, Southern Nuclear submitted two license amendment requests to conform the rebar design details to NRC requirements. On January 29, 2013, the NRC issued "no objection" letters in response to the related preliminary amendment requests, enabling completion of final work supporting the pouring of base mat concrete, which is expected to occur following approval of the license amendment requests in March 2013. Various design and other issues are expected to arise as construction proceeds, which may result in additional license amendments or require other resolution. If any license amendment requests 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, additional delays in the fabrication and assembly of structural modules, the failure of such modules to meet applicable standards, or other issues 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

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 to be placed in service in 2013), which will have a positive impact on the Company's 2013 cash flows.

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 to be 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 will have a positive impact on the future cash flows of the Company through 2014.

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Consequently, the Company's positive cash flow benefit is estimated to be between $170 million and $190 million in 2013.

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 byproducts, 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 March 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. On March 12, 2012, the NRC issued three orders and a request for information based on the July 2011 NRC task force report recommendations that included, among other items, additional mitigation strategies for beyond-design-basis events, enhanced spent fuel pool instrumentation capabilities, hardened vents for certain classes of containment structures, including the one in use at Plant Hatch, site specific evaluations for seismic and flooding hazards, and various plant evaluations to ensure adequate coping capabilities during station blackout and other conditions. On August 29, 2012, the NRC staff issued the final interim staff guidance document, which offers acceptable approaches to meeting the requirements of the NRC's orders before the December 31, 2016 compliance deadline. The interim staff guidance is not mandatory, but licensees would be required to obtain NRC approval for taking an approach other than as outlined in the interim staff guidance. 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 associated compliance costs would have a material impact on the Company's financial statements.

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, nuclear decommissioning, 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.

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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, income tax, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. The Company periodically evaluates its exposure to such risks and, in accordance with GAAP, records reserves for those matters where a non-tax-related loss is considered probable and reasonably estimable and records a tax asset or liability if it is more likely than not that a tax position will be sustained. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect the Company's 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 $14 million or less change in total annual benefit expense and a $175 million or less change in projected obligations.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2012. 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 2013 through 2015, 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, 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, 2012 as compared to December 31, 2011. No contributions to the qualified pension plan were made in 2012. The Company funded approximately $2 million to its nuclear decommissioning trust funds in 2012.

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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 provided from operating activities totaled $2.6 billion in 2011, an increase of $785 million from 2010, primarily due to higher retail operating revenues, increased deferred income taxes in 2011 primarily due to bonus depreciation, and contributions to the qualified pension plan in 2010.

Net cash used for investing activities totaled $2.0 billion, $1.8 billion, and $2.2 billion in 2012, 2011, and 2010, 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)/provided from financing activities totaled $(290) million, $(836) million, and $391 million for 2012, 2011, and 2010, respectively. 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. The increase in cash used in 2011 compared to 2010 was primarily a reflection of lower capital contributions from Southern Company, higher common stock dividends paid to Southern Company, and lower debt issuances due to the availability of more internally generated cash in 2011. 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 2012 include increases of $1.2 billion in total property, plant, and equipment and $688 million in debt, as well as a $367 million change in under/over recovered fuel.

The Company's ratio of common equity to total capitalization, including short-term debt, was 48.3% in 2012 and 49.4% in 2011. See Note 6 to the financial statements for additional information.

Sources of Capital

Except as described below with respect to potential U.S. Department of Energy (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, 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.

In 2010, the Company reached an agreement with the DOE to accept terms for a conditional commitment for federal loan guarantees that would apply to future borrowings by the Company related to the construction of Plant Vogtle Units 3 and 4. Any borrowings guaranteed by the DOE would be full recourse to the Company and secured by a first priority lien on the Company's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4. Total guaranteed borrowings would not exceed the lesser of 70% of eligible project costs, or approximately $3.46 billion, and are expected to be funded by the Federal Financing Bank. Final approval and issuance of loan guarantees by the DOE are subject to negotiation of definitive agreements, completion of due diligence by the DOE, receipt of any necessary regulatory approvals, and satisfaction of other conditions. In the event that the DOE does not issue a loan guarantee or the Company determines that the final terms and conditions of the loan guarantee by the DOE are not in the best interest of its customers, the Company expects to finance the construction of Plant Vogtle Units 3 and 4 through traditional capital markets financings. There can be no assurance that the DOE will issue loan guarantees for the Company. The conditional commitment will expire on June 30, 2013, unless further extended by the DOE. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Nuclear Construction" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Nuclear Construction" for more information on Plant Vogtle Units 3 and 4.

The issuance of long-term securities by the Company is subject to the approval of the Georgia PSC. In addition, the issuance of short-term debt securities by the Company is subject to regulatory approval by the FERC. Additionally, with respect to the public offering of securities, the Company files registration statements with the 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.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Georgia Power Company 2012 Annual Report

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, 2012, the Company had approximately $45 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2012 were as follows:

Expires[a]			
2014	2016	Total	Unused
	(in millions)		
$250	$1,500	$1,750	$1,740

(a) No credit arrangements expire in 2013 or 2015.

See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. These arrangements contain covenants that limit debt levels and contain cross default provisions that are restricted only to the indebtedness of the Company. The Company is currently in compliance with all such covenants. The Company expects to renew its credit arrangements, as needed, prior to expiration.

These credit arrangements 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, 2012 was approximately $865 million.

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[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, 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 %	
December 31, 2010:					
Commercial paper	$575	0.3 %	$167	0.3 %	$575

(a) Excludes notes payable related to other energy service contracts of $2 million in 2012 and 2011 and $1 million in 2010.

(b) Average and maximum amounts are based upon daily balances during the twelve-month periods ended December 31, 2012, 2011, and 2010.

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)
Georgia Power Company 2012 Annual Report

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 May 2012, the Development Authority of Monroe County issued $48.72 million aggregate principal amount of Pollution Control Revenue Bonds (Georgia Power Company Plant Scherer Project), First Series 2012 for the benefit of the Company. The proceeds were used in June 2012 to redeem $48.72 million aggregate principal amount of Development Authority of Monroe County Pollution Control Revenue Bonds (Georgia Power Company Plant Scherer Project), First Series 2006.
In June 2012, the Development Authority of Burke County issued $85 million aggregate principal amount of Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), First Series 2012 and $100 million aggregate principal amount of Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), Second Series 2012 for the benefit of the Company. The proceeds were used in July 2012 to redeem $85 million aggregate principal amount of Development Authority of Burke County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), First Series 2005 and $100 million aggregate principal amount of Development Authority of Burke County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), Second Series 2005.
In November 2012, the Development Authority of Burke County issued $50 million aggregate principal amount of Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), Third Series 2012 for the benefit of the Company. The proceeds were used in December 2012 to redeem $50 million aggregate principal amount of Development Authority of Burke County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), Second Series 1997.
Senior Notes
In March 2012 and May 2012, the Company issued $750 million and $350 million, respectively, aggregate principal amount of Series 2012A 4.30% Senior Notes due March 15, 2042. Also in May 2012, the Company issued $400 million aggregate principal amount of Series 2012B 2.85% Senior Notes due May 15, 2022. In August 2012, the Company issued $400 million aggregate principal amount of Series 2012C 0.75% Senior Notes due August 10, 2015. The net proceeds from these issuances were used to repay a portion of the Company's short-term debt and the bank loans described below under "Other," for the redemption in July 2012 of $300 million aggregate principal amount of the Company's Series 2007D 6.375% Senior Notes due June 15, 2047, the redemption in September 2012 of $250 million aggregate principal amount of the Company's Series 2007E 6.00% Senior Insured Monthly Notes due September 1, 2040, and for general corporate purposes, including the Company's continuous construction program.
In November 2012, the Company's $200 million aggregate principal amount of Series K 5.125% Senior Monthly Notes due November 15, 2012 matured. Also in November 2012, the Company issued $400 million aggregate principal amount of Series 2012D 0.625% Senior Notes due November 15, 2015. The proceeds were used to redeem $100 million aggregate principal amount of the Company's Series 2007F 6.05% Senior Monthly Notes due December 1, 2038, and for general corporate purposes, including the Company's continuous construction program.
Other
In January 2012, the Company entered into a six-month floating rate bank loan in an aggregate amount of $100 million, bearing interest based on one-month London Interbank Offered Rate (LIBOR). The proceeds were used for general corporate purposes, including the Company's continuous construction program. This bank loan was repaid on June 11, 2012.
In March 2012, the Company repaid at maturity two bank loans, each in an aggregate principal amount of $125 million, each bearing interest at a floating rate based on one-month LIBOR.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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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, 2012 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB- and/or Baa3	$65
Below BBB- and/or Baa3	1,284

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.

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 $1.5 billion of outstanding variable rate long-term debt at January 1, 2013 was 0.36%. 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 $15 million at January 1, 2013. 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, 2012 when compared to the December 31, 2011 reporting period.

The changes in fair value of energy-related derivative contracts, substantially all of which are composed of regulatory hedges, for the years ended December 31 were as follows:

	2012 Changes	2011 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	$(82)	$(100)

Contracts realized or settled	71	92
Current period changes[(a)]	(23)	(74)
Contracts outstanding at the end of the period, assets (liabilities), net	$(34)	$(82)

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

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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The changes in the fair value positions of the energy-related derivative contracts, which are substantially all attributable to both the volume and the price of natural gas, for the years ended December 31 were as follows:

	2012 Changes	2011 Changes
	Fair Value (in millions)	
Natural gas swaps	$44	$18
Natural gas options	4	—
Other energy-related derivatives	—	—
Total changes	$48	$18

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

	2012	2011
	mmBtu* Volume (in millions)	
Commodity – Natural gas swaps	12	29
Commodity – Natural gas options	93	44
Total hedge volume	105	73

*million British thermal units (mmBtu)

The weighted average swap contract cost above market prices was approximately $1.09 per mmBtu as of December 31, 2012 and $1.65 per mmBtu as of December 31, 2011. 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, 2012 and 2011, 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 has a 48-month time horizon. The Georgia PSC recently approved changes to the Company's hedging program requiring it to use options and hedges within a 24-month time horizon. Therefore, gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the fuel cost recovery mechanism. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred and were not material for any year presented.

The Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. 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, 2012 were as follows:

	Fair Value Measurements December 31, 2012		
	Total	Maturity	
	Fair Value	Year 1	Years 2&3
	(in millions)		
Level 1	$—	$—	$—
Level 2	(34)	(24)	(10)
Level 3	—	—	—
Fair value of contracts outstanding at end of period	$(34)	$(24)	$(10)

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 $2.2 billion for 2013, $2.4 billion for 2014, and $2.2 billion for 2015. Capital expenditures to comply with existing environmental statutes and regulations included in these estimated amounts are $476 million, $441 million, and $392 million for 2013, 2014, and 2015, respectively. These amounts include capital expenditures related to contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements, as well as capital expenditures and compliance costs associated with the MATS rule.

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, 5, 6, 7, and 11 to the financial statements for additional information.

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Contractual Obligations

	2013	2014-2015	2016-2017	After 2017	Uncertain Timing[d]	Total
	(in millions)					
Long-term debt[a] —						
Principal	$1,675	$1,050	$704	$6,205	$—	$9,634
Interest	338	593	547	4,389	—	5,867
Preferred and preference stock dividends[b]	17	35	35	—	—	87
Financial derivative obligations[c]	30	14	1	—	—	45
Operating leases[d]	30	41	16	3	—	90
Capital leases[d]	5	11	13	21	—	50
Unrecognized tax benefits[e]	—	—	—	—	23	23
Purchase commitments —						
Capital[f]	1,980	4,119	—	—	—	6,099
Fuel[g]	1,967	2,456	1,253	2,123	—	7,799
Purchased power	240	549	627	2,886	—	4,302
Other[h]	52	172	55	452	—	731
Trusts —						
Nuclear decommissioning[i]	2	4	4	31	—	41
Pension and other postretirement benefit plans[j]	40	70	—	—	—	110
Total	$6,376	$9,114	$3,255	$16,110	$23	$34,878

(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, 2013, 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 timing related to the realization of $23 million in unrecognized tax benefits cannot be reasonably and reliably estimated due to uncertainties in the timing of the effective settlement of tax positions. See Note 5 to the financial statements under "Unrecognized Tax Benefits" for additional information.

(f) The Company provides estimated capital expenditures for a three-year period, including capital expenditures and compliance costs associated with existing environmental regulations, including the MATS rule. 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, 2012, 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) 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, 2012.

(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. 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.

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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Cautionary Statement Regarding Forward-Looking Statements
The Company's 2012 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, start and completion dates of construction projects, filings with state and federal regulatory authorities, impact of the Tax Relief Act, 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 byproducts, and emissions of sulfur, nitrogen, carbon, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, financial reform legislation, 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, 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, including the development and construction of facilities with designs that have not been finalized or previously constructed, 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 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, NRC actions, and potential DOE loan guarantees;
- 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;
- 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 the availability or benefits of proposed DOE loan guarantees;

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- 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.

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STATEMENTS OF INCOME
For the Years Ended December 31, 2012, 2011, and 2010
Georgia Power Company 2012 Annual Report

	2012	2011	2010
	(in millions)		
Operating Revenues:			
Retail revenues	$7,362	$8,099	$7,608
Wholesale revenues, non-affiliates	281	341	380
Wholesale revenues, affiliates	20	32	53
Other revenues	335	328	308
Total operating revenues	7,998	8,800	8,349
Operating Expenses:			
Fuel	2,051	2,789	3,102
Purchased power, non-affiliates	315	390	368
Purchased power, affiliates	666	713	578
Other operations and maintenance	1,644	1,777	1,734
Depreciation and amortization	745	715	558
Taxes other than income taxes	374	369	344
Total operating expenses	5,795	6,753	6,684
Operating Income	2,203	2,047	1,665
Other Income and (Expense):			
Allowance for equity funds used during construction	53	96	147
Interest expense, net of amounts capitalized	(366)	(343)	(375)
Other income (expense), net	(17)	(13)	(17)
Total other income and (expense)	(330)	(260)	(245)
Earnings Before Income Taxes	1,873	1,787	1,420
Income taxes	688	625	453
Net Income	1,185	1,162	967
Dividends on Preferred and Preference Stock	17	17	17
Net Income After Dividends on Preferred and Preference Stock	$1,168	$1,145	$950

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

STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2012, 2011, and 2010
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	2012	2011	2010
	(in millions)		
Net Income	$1,185	$1,162	$967
Other comprehensive income (loss):			
Qualifying hedges:			
Reclassification adjustment for amounts included in net income, net of tax of $1, $2, and $6, respectively	2	2	10
Total other comprehensive income (loss)	2	2	10
Comprehensive Income	$1,187	$1,164	$977

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

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STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2012, 2011, and 2010
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	2012	2011	2010
	(in millions)		
Operating Activities:			
Net income	$1,185	$1,162	$967
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization, total	912	867	724
Deferred income taxes	377	500	342
Allowance for equity funds used during construction	(53)	(96)	(147)
Retail fuel cost over recovery—long-term	123	—	—
Pension, postretirement, and other employee benefits	21	(15)	21
Pension and postretirement funding	(12)	(15)	(195)
Other, net	(12)	(22)	(93)
Changes in certain current assets and liabilities —			
-Receivables	205	235	168
-Fossil fuel stock	(269)	(99)	103
-Prepaid income taxes	(7)	72	(36)
-Other current assets	(53)	(21)	(9)
-Accounts payable	(165)	44	(99)
-Accrued taxes	(76)	(36)	31
-Accrued compensation	(18)	7	62
-Retail fuel cost over-recovery—short-term	107	—	—
-Other current liabilities	30	49	8
Net cash provided from operating activities	2,295	2,632	1,847
Investing Activities:			
Property additions	(1,723)	(1,861)	(2,190)
Investment in restricted cash from pollution control bonds	(284)	—	—
Distribution of restricted cash from pollution control bonds	284	—	—
Nuclear decommissioning trust fund purchases	(852)	(1,845)	(1,772)
Nuclear decommissioning trust fund sales	850	1,841	1,768
Cost of removal, net of salvage	(82)	(42)	(67)
Change in construction payables, net of joint owner portion	(149)	123	36
Other investing activities	(17)	(7)	(19)
Net cash used for investing activities	(1,973)	(1,791)	(2,244)
Financing Activities:			
Increase (decrease) in notes payable, net	(513)	(61)	252
Proceeds —			
Capital contributions from parent company	42	214	688
Pollution control revenue bonds issuances and remarketings	284	604	—
Senior notes issuances	2,300	550	1,950
Other long-term debt issuances	—	250	—
Redemptions and repurchases —			
Pollution control revenue bonds	(284)	(339)	(516)
Senior notes	(850)	(427)	(1,112)

Other long-term debt	(250)	(303)	—
Long-term debt to affiliate trust	—	(206)	—
Payment of preferred and preference stock dividends	(17)	(17)	(18)
Payment of common stock dividends	(983)	(1,096)	(820)
Other financing activities	(19)	(5)	(33)
Net cash provided from (used for) financing activities	(290)	(836)	391
Net Change in Cash and Cash Equivalents	32	5	(6)
Cash and Cash Equivalents at Beginning of Year	13	8	14
Cash and Cash Equivalents at End of Year	$45	$13	$8
Supplemental Cash Flow Information:			
Cash paid during the period for —			
Interest (net of $21, $37 and $54 capitalized, respectively)	$337	$346	$339
Income taxes (net of refunds)	312	54	149
Noncash transactions - accrued property additions at year-end	261	391	310

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

BALANCE SHEETS
At December 31, 2012 and 2011
Georgia Power Company 2012 Annual Report

Assets	2012	2011
	(in millions)	
Current Assets:		
Cash and cash equivalents	$45	$13
Receivables —		
Customer accounts receivable	484	571
Unbilled revenues	217	172
Under recovered regulatory clause revenues	—	137
Joint owner accounts receivable	51	87
Other accounts and notes receivable	68	61
Affiliated companies	23	26
Accumulated provision for uncollectible accounts	(6)	(13)
Fossil fuel stock, at average cost	992	723
Materials and supplies, at average cost	452	406
Vacation pay	85	82
Prepaid income taxes	164	71
Other regulatory assets, current	72	108
Other current assets	104	106
Total current assets	2,751	2,550
Property, Plant, and Equipment:		
In service	29,244	27,804
Less accumulated provision for depreciation	10,431	10,296
Plant in service, net of depreciation	18,813	17,508
Other utility plant, net	263	55
Nuclear fuel, at amortized cost	497	443
Construction work in progress	2,893	3,274
Total property, plant, and equipment	22,466	21,280
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	45	63
Nuclear decommissioning trusts, at fair value	698	667
Miscellaneous property and investments	44	44
Total other property and investments	787	774
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	733	756
Other regulatory assets, deferred	1,798	1,604
Other deferred charges and assets	268	187
Total deferred charges and other assets	2,799	2,547
Total Assets	$28,803	$27,151

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

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BALANCE SHEETS
At December 31, 2012 and 2011
Georgia Power Company 2012 Annual Report

Liabilities and Stockholder's Equity	2012 (in millions)	2011
Current Liabilities:		
Securities due within one year	$1,680	$455
Notes payable	2	515
Accounts payable —		
Affiliated	417	337
Other	436	686
Customer deposits	237	213
Accrued taxes —		
Accrued income taxes	6	50
Other accrued taxes	260	304
Accrued interest	100	92
Accrued vacation pay	61	60
Accrued compensation	113	125
Liabilities from risk management activities	30	68
Other regulatory liabilities, current	73	65
Nuclear decommissioning trust securities lending collateral	9	32
Over recovered regulatory clause revenues, current	107	—
Other current liabilities	137	139
Total current liabilities	3,668	3,141
Long-Term Debt (See accompanying statements)	7,994	8,018
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	4,861	4,388
Deferred credits related to income taxes	115	122
Accumulated deferred investment tax credits	208	220
Employee benefit obligations	950	905
Asset retirement obligations	1,097	734
Other cost of removal obligations	63	110
Other deferred credits and liabilities	308	224
Total deferred credits and other liabilities	7,602	6,703
Total Liabilities	19,264	17,862
Preferred Stock (See accompanying statements)	45	45
Preference Stock (See accompanying statements)	221	221
Common Stockholder's Equity (See accompanying statements)	9,273	9,023
Total Liabilities and Stockholder's Equity	$28,803	$27,151
Commitments and Contingent Matters (See notes)		

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

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STATEMENTS OF CAPITALIZATION
At December 31, 2012 and 2011
Georgia Power Company 2012 Annual Report

	2012	2011	2012	2011
	(in millions)		(percent of total)	
Long-Term Debt:				
Long-term notes payable —				
Variable rate (0.85% to 0.95% at 1/1/12) due 2012	$—	$250		
Variable rate (0.58% to 0.63% at 1/1/13) due 2013	650	650		
5.125% due 2012	—	200		
1.30% to 6.00% due 2013	1,025	1,025		
0.625% to 5.25% due 2015	1,050	250		
3.00% due 2016	250	250		
5.70% due 2017	450	450		
2.85% to 8.20% due 2018-2048	4,425	3,575		
Total long-term notes payable	7,850	6,650		
Other long-term debt —				
Pollution control revenue bonds:				
0.80% to 5.75% due 2022-2049	919	916		
Variable rate (0.17% at 1/1/13) due 2016	4	4		
Variable rate (0.12% to 0.24% at 1/1/13) due 2018-2052	861	864		
Total other long-term debt	1,784	1,784		
Capitalized lease obligations	50	55		
Unamortized debt discount	(10)	(16)		
Total long-term debt (annual interest requirement — $338 million)	9,674	8,473		
Less amount due within one year	1,680	455		
Long-term debt excluding amount due within one year	7,994	8,018	45.6 %	46.4 %
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	1.5	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	5,585	5,522		
Retained earnings	3,297	3,112		

Accumulated other comprehensive loss	(7)	(9)		
Total common stockholder's equity	9,273	9,023	52.9	52.1
Total Capitalization	$17,533	$17,307	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, 2012, 2011, and 2010
Georgia Power Company 2012 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, 2009	9	$398	$4,593	$2,933	$(21)	$7,903
Net income after dividends on preferred and preference stock	—	—	—	950	—	950
Capital contributions from parent company	—	—	698	—	—	698
Other comprehensive income (loss)	—	—	—	—	10	10
Cash dividends on common stock	—	—	—	(820)	—	(820)
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

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

NOTES TO FINANCIAL STATEMENTS
Georgia Power Company 2012 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 and power pool transactions. Costs for these services amounted to $540 million in 2012, $550 million in 2011, and $552 million in 2010. 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 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 $574 million in 2012, $537 million in 2011, and $473 million in 2010.
The Company has entered into several power purchase agreements (PPA) with Southern Power for capacity and energy. Expenses associated with these PPAs were $147 million, $171 million, and $199 million in 2012, 2011, and 2010, respectively. Additionally, the Company had $15 million and $16 million of prepaid capacity expenses included

in deferred charges and other assets in the balance sheets at December 31, 2012 and 2011, respectively. See Note 7 under "Fuel and Purchased Power Agreements" for additional information.

The Company has an agreement with Gulf Power under which Gulf Power jointly owns a 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 $7 million in 2012, $7 million in 2011, and $9 million in 2010. 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 2012, 2011, or 2010.

NOTES (continued)
Georgia Power Company 2012 Annual Report

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.

New Accounting Pronouncements

In June 2011, the Financial Accounting Standards Board (FASB) issued guidance, ASU 2011-05, Presentation of Comprehensive Income, requiring companies to present the total of comprehensive income, the components of net income, and the components of other comprehensive income, in a single continuous statement of comprehensive income or in two separate but consecutive statements. In October 2012, the FASB issued additional guidance, ASU 2012-04, Technical Corrections and Improvements (ASU 2012-04), in which it clarified that those companies presenting consecutive statements must begin the statement of comprehensive income with net income. The Company retroactively adopted the guidance in ASU 2012-04 beginning with its financial statements for the three years ended December 31, 2012, 2011, and 2010.

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 2012 Annual Report

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

	2012	2011	Note
	(in millions)		
Retiree benefit plans	$1,331	$1,197	(a, j)
Deferred income tax charges	695	713	(b)
Deferred income tax charges — Medicare subsidy	43	47	(c)
Loss on reacquired debt	190	178	(d)
Asset retirement obligations	131	108	(b, j)
Fuel hedging (realized and unrealized) losses	49	104	(e)
Vacation pay	85	82	(f, j)
Building leases	40	43	(g)
Cancelled construction projects	65	12	(h)
Other regulatory assets	100	108	(c)
Other cost of removal obligations	(94)	(141)	(b)
Deferred income tax credits	(115)	(122)	(b)
State income tax credits	(36)	(62)	(i)
Other regulatory liabilities	(13)	(13)	(d, e)
Total regulatory assets (liabilities), net	$2,471	$2,254	

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 under "Pension Plans" and "Other Postretirement Benefits" for additional information.

(b) Asset retirement and other cost of removal obligations and deferred income tax assets are recovered, and deferred income tax liabilities are amortized over the related property lives, which may range up to 65 years. Asset retirement and removal liabilities will be settled and trued up following completion of the related activities. At December 31, 2012, other cost of removal obligations included $31 million that will be amortized during 2013 in accordance with the Company's Alternate Rate Plan for the years 2011 through 2013 (2010 ARP). See Note 3 under "Retail Regulatory Matters – Rate Plans" for additional information.

(c) Recorded and recovered or amortized as approved by the Georgia PSC over periods generally not exceeding 10 years.

(d) Recovered over either the remaining life of the original issue or, if refinanced, over the life of the new issue, which may range up to 50 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 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 deferred in accordance with the 2010 ARP. Amortization is expected to begin January 1, 2014, subject to approval by the Georgia PSC.

(i) Additional tax benefits resulting from the Georgia state income tax credit settlement that are being amortized over a 21-month period that began in April 2012, in accordance with a Georgia PSC order. See Note 5 under "Current and Deferred Income Taxes" for additional information.

(j) 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 reflected in rate base. See Note 3 under "Retail Regulatory Matters" for additional information.

NOTES (continued)
Georgia Power Company 2012 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, the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between the actual recoverable costs and amounts billed in current regulated rates.
The Company has a diversified base of customers. No single customer or industry comprises 10% or more of revenues. For all periods presented, uncollectible accounts averaged less than 1% of revenues.
Fuel Costs
Fuel costs are expensed as the fuel is used. Fuel expense 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 utilized are deferred and amortized to income as a credit to reduce depreciation 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 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:

	2012	2011
	(in millions)	
Generation	$14,567	$13,675
Transmission	4,581	4,355
Distribution	8,373	8,125
General	1,695	1,621
Plant acquisition adjustment	28	28
Total plant in service	$29,244	$27,804

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 expense 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 defers the costs of certain significant inspection costs for the combustion turbines at Plant McIntosh and amortizes such costs over 10 years, which approximates the expected maintenance cycle.

NOTES (continued)
Georgia Power Company 2012 Annual Report

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 2.9% in 2012, 2.8% in 2011, and 3.0% in 2010. Depreciation studies are conducted periodically to update the composite rates that are approved by the Georgia PSC and the FERC. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation are removed from 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 the Company to amortize a portion of its regulatory liability related to other cost of removal obligations. Under the terms of the 2010 ARP, the Company is amortizing approximately $31 million annually of the remaining regulatory liability related to other cost of removal obligations over the three years ending December 31, 2013. See Note 3 under "Retail Regulatory Matters – Rate Plans" for additional information.

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. See Note 3 under "Retail Regulatory Matters – Rate Plans" for additional information related to the Company's cost of removal 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. However, liabilities for the removal of these assets have not been recorded because the range of time over which the Company may settle these obligations is unknown and cannot be reasonably estimated. 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:

	2012	2011
	(in millions)	
Balance at beginning of year	$757	$712
Liabilities incurred	24	—
Liabilities settled	(15)	(9)
Accretion	72	45
Cash flow revisions	267	9
Balance at end of year	$1,105	$757

Nuclear Decommissioning

The 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, 2012 and 2011, approximately $91 million and $39 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 $93 million and $42 million at December 31, 2012 and 2011, 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, 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. At December 31, 2011, investment securities in the Funds totaled $666 million, consisting of equity securities of $244 million, debt securities of $397 million, and $25 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 $850 million, $1.8 billion, and $1.8 billion in 2012, 2011, and 2010, respectively, all of which were reinvested. 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. For 2010, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $74 million, of which $25 million related to unrealized losses on securities held in the Funds at December 31, 2010. 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)
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Site study cost is the estimate to decommission a specific facility as of the site study year. 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, 2012 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	$435	$256

The decommissioning periods and site study costs for Plant Vogtle Units 1 and 2 reflect the extended operating license approved by the NRC in 2009. 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.

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 2009. The Georgia PSC approved annual decommissioning costs for ratemaking of $2 million annually for Plant Hatch for 2011 through 2013. 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 facilities. While cash is not realized currently from such allowance, AFUDC increases the revenue requirement over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in calculating taxable income. For the years 2012, 2011, and 2010, the average AFUDC rates were 6.8%, 7.5%, and 8.0%, respectively, and AFUDC capitalized was $75 million, $134 million, and $201 million, respectively. AFUDC, net of income taxes, was 5.7%, 10.4%, and 19.0% of net income after dividends on preferred and preference stock for 2012, 2011, and 2010, respectively. See Note 3 under "Construction – Nuclear" 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.

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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 effective January 1, 2011, the Company recovers $18 million annually. In 2010, the Company recovered $21 million annually as mandated by the retail rate plan effective January 1, 2008 (2007 Retail Rate Plan). At December 31, 2012, the Company's regulatory asset related to storm damage was $38 million, with approximately $18 million included in other regulatory assets, current and approximately $20 million included as other regulatory assets, deferred. 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. Under the 2010 ARP, effective January 1, 2011, the Company recovers approximately $3 million annually through the environmental compliance cost recovery (ECCR) tariff. In 2010, the Company recovered $1 million annually in accordance with the 2007 Retail Rate Plan. 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, 2012, the balance of the environmental remediation liability was $19 million, with approximately $3 million included in other regulatory assets, current and approximately $11 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, 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 fuel cost recovery rates approved by the Georgia PSC. Emissions allowances granted by the 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, 2012.

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.

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Comprehensive Income
The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income, changes in the fair value of qualifying cash flow hedges, and reclassifications for amounts included in net income.

2. RETIREMENT BENEFITS
The Company has a defined benefit, trusteed, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions to the qualified pension plan were made for the year ended December 31, 2012. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2013. 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, 2013, other postretirement trust contributions are expected to total approximately $24 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 2009 for the 2010 plan year using discount rates for the pension plans and the other postretirement benefit plans of 5.93% and 5.83%, respectively, and an annual salary increase of 4.18%.

	2012		2011		2010	
Discount rate:						
Pension plans	4.27	%	4.98	%	5.52	%
Other postretirement benefit plans	4.04		4.87		5.40	
Annual salary increase	3.59		3.84		3.84	
Long-term return on plan assets:						
Pension plans	8.20		8.45		8.45	
Other postretirement benefit plans	7.24		7.25		7.24	

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) is the weighted average medical care cost trend rate. The weighted average medical care cost trend rates used in measuring the APBO as of December 31, 2012 were as follows:

	Initial Cost Trend Rate	Ultimate Cost Trend Rate	Year That Ultimate Rate Is

			Reached
Pre-65	8.00%	5.00%	2020
Post-65 medical	6.00	5.00	2020
Post-65 prescription	6.00	5.00	2020

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An annual increase or decrease in the assumed medical care cost trend rate of 1% would affect the APBO and the service and interest cost components at December 31, 2012 as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$61	$(52)
Service and interest costs	3	(3)

Pension Plans
The total accumulated benefit obligation for the pension plans was $3.1 billion at December 31, 2012 and $2.7 billion at December 31, 2011. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2012 and 2011 were as follows:

	2012	2011
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	$2,909	$2,674
Service cost	60	57
Interest cost	141	144
Benefits paid	(136)	(132)
Actuarial loss	338	166
Balance at end of year	3,312	2,909
Change in plan assets		
Fair value of plan assets at beginning of year	2,575	2,621
Actual return on plan assets	377	76
Employer contributions	11	10
Benefits paid	(136)	(132)
Fair value of plan assets at end of year	2,827	2,575
Accrued liability	$(485)	$(334)

At December 31, 2012, the projected benefit obligations for the qualified and non-qualified pension plans were $3.1 billion and $165 million, respectively. All pension plan assets are related to the qualified pension plan.
Amounts recognized in the balance sheets at December 31, 2012 and 2011 related to the Company's pension plans consist of the following:

	2012	2011
	(in millions)	
Other regulatory assets, deferred	$1,132	$995
Current liabilities, other	(11)	(10)
Employee benefit obligations	(474)	(324)

NOTES (continued)
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Presented below are the amounts included in regulatory assets at December 31, 2012 and 2011 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 2013.

	2012	2011	Estimated Amortization in 2013
	(in millions)		
Prior service cost	$37	$48	$10
Net (gain) loss	1,095	947	74
Other regulatory assets, deferred	$1,132	$995	

The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2012 and 2011 are presented in the following table:

	Regulatory Assets
	(in millions)
Balance at December 31, 2010	$689
Net (gain) loss	324
Change in prior service costs	—
Reclassification adjustments:	
Amortization of prior service costs	(12)
Amortization of net gain (loss)	(6)
Total reclassification adjustments	(18)
Total change	306
Balance at December 31, 2011	$995
Net (gain) loss	182
Change in prior service costs	—
Reclassification adjustments:	
Amortization of prior service costs	(12)
Amortization of net gain (loss)	(33)
Total reclassification adjustments	(45)
Total change	137
Balance at December 31, 2012	$1,132

Components of net periodic pension cost (income) were as follows:

	2012	2011	2010
	(in millions)		
Service cost	$60	$57	$54
Interest cost	141	144	145
Expected return on plan assets	(221)	(234)	(220)
Recognized net loss	33	6	2
Net amortization	12	12	13
Net periodic pension cost (income)	$25	$(15)	$(6)

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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, 2012, estimated benefit payments were as follows:

	Benefit Payments (in millions)
2013	$148
2014	154
2015	160
2016	166
2017	173
2018 to 2022	952

Other Postretirement Benefits

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2012 and 2011 were as follows:

	2012	2011
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	$774	$786
Service cost	7	7
Interest cost	37	41
Benefits paid	(46)	(48)
Actuarial (gain) loss	25	(4)
Plan amendments	—	(12)
Retiree drug subsidy	3	4
Balance at end of year	800	774
Change in plan assets		
Fair value of plan assets at beginning of year	365	393
Actual return (loss) on plan assets	43	(4)
Employer contributions	17	20
Benefits paid	(43)	(44)
Fair value of plan assets at end of year	382	365
Accrued liability	$(418)	$(409)

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Amounts recognized in the balance sheets at December 31, 2012 and 2011 related to the Company's other postretirement benefit plans consist of the following:

	2012	2011
	(in millions)	
Regulatory assets	$187	$186
Employee benefit obligations	(418)	(409)

Presented below are the amounts included in regulatory assets at December 31, 2012 and 2011 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 2013.

	2012	2011	Estimated Amortization in 2013
	(in millions)		
Prior service cost	$(4)	$(4)	$—
Net (gain) loss	186	179	7
Transition obligation	5	11	4
Regulatory assets	$187	$186	

The changes in the balance of regulatory assets related to the other postretirement benefit plans for the plan years ended December 31, 2012 and 2011 are presented in the following table:

	Regulatory Assets (in millions)
Balance at December 31, 2010	$179
Net (gain) loss	29
Change in prior service costs/transition obligation	(12)
Reclassification adjustments:	
Amortization of transition obligation	(6)
Amortization of prior service costs	(1)
Amortization of net gain (loss)	(3)
Total reclassification adjustments	(10)
Total change	7
Balance at December 31, 2011	$186
Net (gain) loss	11
Change in prior service costs/transition obligation	—
Reclassification adjustments:	
Amortization of transition obligation	(6)
Amortization of prior service costs	—
Amortization of net gain (loss)	(4)
Total reclassification adjustments	(10)
Total change	1
Balance at December 31, 2012	$187

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

	2012	2011	2010
	(in millions)		
Service cost	$7	$7	$9
Interest cost	37	41	44
Expected return on plan assets	(29)	(30)	(30)
Net amortization	10	11	10
Net postretirement cost	$25	$29	$33

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)		
2013	$49	$(5)	$44
2014	51	(5)	46
2015	53	(5)	48
2016	55	(6)	49
2017	56	(7)	49
2018 to 2022	282	(36)	246

Benefit Plan Assets

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

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The composition of the Company's pension plan and other postretirement benefit plan assets as of December 31, 2012 and 2011, along with the targeted mix of assets for each plan, is presented below:

	Target	2012	2011
Pension plan assets:			
Domestic equity	26%	28%	29%
International equity	25	24	25
Fixed income	23	27	23
Special situations	3	1	—
Real estate investments	14	13	14
Private equity	9	7	9
Total	100%	100%	100%
Other postretirement benefit plan assets:			
Domestic equity	41%	34%	39%
International equity	21	27	22
Domestic fixed income	24	27	26
Global fixed income	8	7	8
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, 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.
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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.

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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, 2012 and 2011. 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:

- Investments in equity securities: 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.
- Investments in fixed income securities: 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.
- Investments in 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.
- Investments in private equity and real estate: 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.

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The fair values of pension plan assets as of December 31, 2012 and 2011 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, 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:				
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.

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As of December 31, 2011:	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*	$437	$202	$—	$639
International equity*	449	129	—	578
Fixed income:				
U.S. Treasury, government, and agency bonds	—	164	—	164
Mortgage- and asset-backed securities	—	51	—	51
Corporate bonds	—	316	1	317
Pooled funds	—	144	—	144
Cash equivalents and other	—	53	—	53
Real estate investments	83	—	296	379
Private equity	—	—	220	220
Total	$969	$1,059	$517	$2,545

* 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, 2012 and 2011 were as follows:

	2012 Real Estate Investments (in millions)	Private Equity	2011 Real Estate Investments	Private Equity
Beginning balance	$296	$220	$258	$245
Actual return on investments:				
Related to investments held at year end	2	—	24	(5)
Related to investments sold during the year	1	2	8	14
Total return on investments	3	2	32	9
Purchases, sales, and settlements	—	(11)	6	(34)
Transfers into/out of Level 3	—	—	—	—
Ending balance	$299	$211	$296	$220

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The fair values of other postretirement benefit plan assets as of December 31, 2012 and 2011 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, 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*	$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.

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As of December 31, 2011:	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*	$85	$24	$—	$109
International equity*	15	31	—	46
Fixed income:				
U.S. Treasury, government, and agency bonds	—	5	—	5
Mortgage- and asset-backed securities	—	1	—	1
Corporate bonds	—	10	—	10
Pooled funds	—	38	—	38
Cash equivalents and other	—	26	—	26
Trust-owned life insurance	—	131	—	131
Real estate investments	3	—	9	12
Private equity	—	—	7	7
Total	$103	$266	$16	$385

* 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, 2012 and 2011 were as follows:

	2012 Real Estate Investments (in millions)	Private Equity	2011 Real Estate Investments	Private Equity
Beginning balance	$9	$7	$8	$8
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)
Transfers into/out of Level 3	—	—	—	—
Ending balance	$10	$7	$9	$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 2012, 2011, and 2010 were $24 million, $24 million, and $23 million, respectively.

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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 byproducts, 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
In 1999, the EPA brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including the Company, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. The EPA alleged NSR violations at three coal-fired generating facilities operated by the Company and five coal-fired generating facilities operated by Alabama Power. The civil action sought penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. The case against the Company was administratively closed in 2001 and has not been reopened.
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.
Climate Change Litigation
Kivalina Case
In 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs allege that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that some of the defendants (including Southern Company) acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. In 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case. On September 21, 2012, the U.S. Court of Appeals for the Ninth Circuit upheld the U.S. District Court for the Northern District of California's dismissal of the case. On November 27, 2012, the U.S. Court of Appeals for the Ninth Circuit denied the plaintiffs' request for review of the decision. On February 25, 2013, the plaintiffs filed a petition for writ of certiorari with the U.S. Supreme Court. Southern Company believes that these claims are without merit. While Southern Company believes the likelihood of loss is remote based on existing case law, it is not possible to predict with certainty whether the Company will incur any liability in connection with this matter. The ultimate outcome of this matter cannot be determined at this time.

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Hurricane Katrina Case
In 2005, immediately following Hurricane Katrina, a lawsuit was filed in the U.S. District Court for the Southern District of Mississippi by Ned Comer on behalf of Mississippi residents seeking recovery for property damage and personal injuries caused by Hurricane Katrina. In 2006, the plaintiffs amended the complaint to include Southern Company and many other electric utilities, oil companies, chemical companies, and coal producers. The plaintiffs allege that the defendants contributed to climate change, which contributed to the intensity of Hurricane Katrina. In 2007, the U.S. District Court for the Southern District of Mississippi dismissed the case. On appeal to the U.S. Court of Appeals for the Fifth Circuit, a three-judge panel reversed the U.S. District Court for the Southern District of Mississippi, holding that the case could proceed, but, on rehearing, the full U.S. Court of Appeals for the Fifth Circuit dismissed the plaintiffs' appeal, resulting in reinstatement of the decision of the U.S. District Court for the Southern District of Mississippi in favor of the defendants. In May 2011, the plaintiffs filed an amended version of their class action complaint, arguing that the earlier dismissal was on procedural grounds and under Mississippi law the plaintiffs have a right to re-file. The amended complaint was also filed against numerous chemical, coal, oil, and utility companies, including the Company. On March 20, 2012, the U.S. District Court for the Southern District of Mississippi dismissed the plaintiffs' amended complaint. On April 16, 2012, the plaintiffs appealed the case to the U.S. Court of Appeals for the Fifth Circuit. The Company believes that these claims are without merit. While the Company believes the likelihood of loss is remote based on existing case law, it is not possible to predict with certainty whether the Company will incur any liability in connection with this matter. 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 large 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 on the Georgia Hazardous Sites Inventory and the CERCLA NPL 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 September 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. In November 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 November 2011 that it is considering enforcement options against the Company and other non-complying UAO recipients. If 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 court granted the Company's summary judgment motion ruling that the Company has no liability in the private action. The plaintiffs may appeal the court'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 treatment 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

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substantially all 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 accrue until the issue is resolved or storage is provided. No amounts have been recognized in the financial statements as of December 31, 2012 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 the customers.

Sufficient pool storage capacity for spent fuel is available at Plant Vogtle Units 1 and 2 to maintain full-core discharge capability for both units into 2014. Construction of an on-site dry storage facility at Plant Vogtle Units 1 and 2 has begun. The facility is expected to begin operation in sufficient time to maintain full-core discharge capability, with additional on-site dry storage to be added as needed. At Plant Hatch, an on-site dry spent fuel storage facility is operational and can be expanded to accommodate spent fuel through the expected life of the plant.

Retail Regulatory Matters

Rate Plans

The economic recession significantly reduced the Company's revenues upon which retail rates were set under the 2007 Retail Rate Plan. In 2009, despite stringent efforts to reduce expenses, the Company's projected retail return on common equity (ROE) for both 2009 and 2010 was below 10.25%. However, in lieu of a full base rate case to increase customer rates as allowed under the 2007 Retail Rate Plan, in 2009, the Georgia PSC approved the Company's request for an accounting order. Under the terms of the accounting order, the Company could amortize up to $108 million of the regulatory liability related to other cost of removal obligations in 2009 and up to $216 million in 2010, limited to the amount needed to earn no more than a 9.75% and 10.15% retail ROE in 2009 and 2010, respectively. For the years ended December 31, 2009 and 2010, the Company amortized $41 million and $174 million, respectively, of the regulatory liability related to other cost of removal obligations.

In 2010, the Georgia PSC approved the 2010 ARP, which became effective January 1, 2011. The terms of the 2010 ARP reflect a settlement agreement among the Company, the Georgia PSC Public Interest Advocacy Staff, and eight other intervenors. Under the terms of the 2010 ARP, the Company is amortizing approximately $92 million of its remaining regulatory liability related to other cost of removal obligations over the three years ending December 31, 2013.

Also under the terms of the 2010 ARP, effective January 1, 2011, the Company increased its (1) traditional base tariff rates by approximately $347 million; (2) Demand-Side Management (DSM) tariff rates by approximately $31 million; (3) ECCR tariff rate by approximately $168 million; and (4) Municipal Franchise Fee (MFF) tariff rate by approximately $16 million, for a total increase in base revenues of approximately $562 million.

Under the 2010 ARP, the following additional base rate adjustments have been made to the Company's tariffs in 2012 and 2013:

- Effective January 1, 2012 and 2013, the DSM tariffs increased by $17 million and $14 million, respectively;
- Effective April 1, 2012 and January 1, 2013, the traditional base tariffs increased by an estimated $122 million and $58 million, respectively, to recover the revenue requirements for Plant McDonough-Atkinson Units 4, 5, and 6 for the period through December 31, 2013; and
- The MFF tariff increased consistently with the adjustments above, as well as those related to the interim fuel rider (IFR) and Nuclear Construction Cost Recovery (NCCR) tariff adjustments described herein under "Fuel Cost

Recovery" and "Nuclear Construction."

Under the 2010 ARP, the Company's allowed retail ROE is set at 11.15%, and earnings will be evaluated against a retail ROE range of 10.25% to 12.25%. Two-thirds of any earnings above 12.25% will be directly refunded to customers, with the remaining one-third retained by the Company. There were no refunds related to earnings for 2011 or 2012. The Company is required to file a general base rate case by July 1, 2013, in response to which the Georgia PSC would be expected to determine whether the 2010 ARP should be continued, modified, or discontinued.

Integrated Resource Plans

On March 20, 2012, the Georgia PSC approved the Company's request to decertify and retire Plant Branch Units 1 and 2 as of December 31, 2013 and October 31, 2013, the compliance dates for the respective units under the Georgia Multi-Pollutant Rule,

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and an oil-fired unit at Plant Mitchell as of March 26, 2012, as requested in the 2011 Integrated Resource Plan (IRP). The Georgia PSC also approved three PPAs totaling 998 MWs with Southern Power for capacity and energy that will commence in 2015 and end in 2030. On November 21, 2012, the FERC accepted the PPAs.
Separately, on March 20, 2012, the Georgia PSC certified 495 MWs of wholesale capacity to be returned to retail service in 2015 and 2016 under a 2010 agreement, subject to the decertification of any related generating units including 243 MWs of the 16 units described below.
Separately, on October 16, 2012, the Georgia PSC approved a 50 MW PPA with a small power production facility (80 MWs or less) that is a qualifying facility under the Public Utility Regulatory Policies Act of 1978 for capacity and energy that will commence in 2015 and end in 2035.
In addition, on November 20, 2012, the Georgia PSC approved the Company's advanced solar initiative. The Company may acquire up to 210 MWs of additional solar capacity over a three-year period through long-term contracts.
On January 31, 2013, the Company filed its triennial IRP (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.
The Company requested the decertification of Plant Boulevard Units 2 and 3 (28 MWs) upon approval of the 2013 IRP and the decertification of Plant Bowen Unit 6 (32 MWs) by April 16, 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 retired by April 16, 2015, the compliance date of the EPA's final Mercury and Air Toxics Standards (MATS) rule. The Company has also requested a revision to the decertification date of Plant Branch Unit 1 from December 31, 2013 to April 16, 2015. To allow for necessary transmission reliability improvements, the Company expects to seek a one-year extension of the MATS rule compliance date for Plant Kraft Units 1 through 4 (316 MWs) and to retire these units by April 16, 2016.
The filing also included the Company's request to switch the primary fuel source for Plant Yates Units 6 and 7 from coal to natural gas. Additionally, the Company plans to switch the primary fuel source for Plant McIntosh Unit 1 from Central Appalachian coal to Powder River Basin (PRB) coal following further evaluation, including a successful test burn of the PRB fuel.
Under the terms of the 2010 ARP, any costs associated with changes to the Company's approved environmental operating or capital budgets resulting from new or revised environmental regulations through 2013 that are approved by the Georgia PSC in connection with an updated IRP will be deferred as a regulatory asset to be recovered over a time period deemed appropriate by the Georgia PSC. In connection with the retirement decisions, the Company reclassified the retail portion of the net carrying value of Plant Branch Units 1 through 4 from plant in service, net of depreciation, to other utility plant, net. The Company is continuing to depreciate these units using the current composite straight-line rates previously approved by the Georgia PSC. Upon actual retirement, the Georgia PSC approved the continued deferral and amortization of the remaining net carrying values for Plant Branch Units 1 and 2 in its order for the 2011 IRP and the Company has requested similar treatment for Plant Branch Units 3 and 4 in the 2013 IRP. The Company also reclassified the construction work in progress (CWIP) balances totaling $65 million related to environmental controls for Plant Branch Units 1 through 4 and Plant Yates Units 6 and 7 that will not be completed as a result of the retirement decisions to regulatory assets and ceased accruing AFUDC. The Georgia PSC approved a three-year amortization period beginning January 2014 for the $13 million balance relating to Plant Branch Units 1 and 2 in its order for the 2011 IRP and the Company has requested similar treatment for the balances related to Plant Branch Units 3 and 4 and Plant Yates Units 6 and 7 in the 2013 IRP. The Company has also requested that the Georgia PSC approve the deferral of the costs associated with material and supplies remaining at the unit retirement dates to a regulatory asset, to be amortized over a time period deemed appropriate by the Georgia PSC. As

a result of this regulatory treatment, the decertification of these units is not expected to have a material impact on the Company's financial statements. The Georgia PSC is scheduled to vote on the 2013 IRP by July 2013.

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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. In addition, the Georgia PSC has authorized an IFR, which allows the Company to adjust its fuel cost recovery rates prior to the next fuel case if the under or over recovered fuel balance exceeds $215 million through February 2013 and $200 million thereafter. 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. The Company expects to file its next fuel case by March 1, 2014.
The Company's over recovered fuel balance totaled approximately $230 million at December 31, 2012 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 and, at certain stages of the work, cancellation fees to the Contractor. 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 Georgia PSC originally certified construction costs of $6.4 billion to place Plant Vogtle Units 3 and 4 into service in April 2016 and April 2017, respectively, and approved inclusion of the related CWIP accounts in rate base. Also in 2009, the State of Georgia enacted the Georgia Nuclear Energy Financing Act, which allows the Company to recover financing costs for nuclear construction projects through annual adjustments to an NCCR tariff by including the related CWIP accounts in rate base during the construction period. With respect to Plant Vogtle Units 3 and 4, this legislation allowed the Company, beginning in 2011, to recover an estimated $1.7 billion of related financing costs during the construction period. As a result, in 2009, the Georgia PSC also revised the certified in-service capital cost

to approximately $4.4 billion.

The Georgia PSC approved increases to the NCCR tariff of approximately $223 million, $35 million, and $50 million, effective January 1, 2011, 2012, and 2013, 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, 2012, approximately $55 million of these 2009 and 2010 costs remained unamortized in CWIP. At December 31, 2012, the Company's CWIP balance for Plant Vogtle Units 3 and 4 totaled $2.3 billion.

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) on February 10, 2012. Receipt of the COLs allowed full construction to begin.

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On February 16, 2012, separate groups of petitioners filed petitions in the U.S. Court of Appeals for the District of Columbia Circuit seeking judicial review of the NRC's issuance of the COLs and certification of the DCD. These petitions were consolidated on April 3, 2012. On April 18, 2012, another group of petitioners filed a motion to stay the effectiveness of the COLs with the U.S. District Court for the District of Columbia. On July 11, 2012, the U.S. Court of Appeals for the District of Columbia Circuit denied the petitioners' motion to stay the effectiveness of the COLs. The Company has intervened in, and intends to vigorously contest, these petitions. Additional technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4, at the federal and state level, are expected as construction proceeds.

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. On February 19, 2013, the Georgia PSC voted to approve the Company's seventh VCM report, including construction capital costs incurred through June 30, 2012 of approximately $2.0 billion. The Company's eighth VCM report requests approval for an additional $0.2 billion of construction capital costs incurred through December 31, 2012. 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 eighth VCM also requests an amendment to the certificate to increase the estimated in-service capital cost of Plant Vogtle Units 3 and 4 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. Associated financing costs during the construction period are estimated to total approximately $2.0 billion.

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 Contractor has claimed that its estimated adjustment attributable to the Company (based on the Company's ownership interest) is approximately $425 million (in 2008 dollars) with respect to these issues. 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. On November 1, 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 on November 1, 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. While litigation has commenced and the Company intends to vigorously defend its positions, the Company 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.

In addition, there are processes in place that are designed to assure compliance with the requirements specified in the DCD and the COLs, including rigorous inspections by Southern Nuclear and the NRC that occur throughout construction. During the fourth quarter 2012, certain details of the rebar design for the Plant Vogtle Unit 3 nuclear island were evaluated for consistency with the DCD and a few non-safety-related deviations were identified. On January 15, 2013 and January 18, 2013, Southern Nuclear submitted two license amendment requests to conform the rebar design details to NRC requirements. On January 29, 2013, the NRC issued "no objection" letters in response to the related preliminary amendment requests, enabling completion of final work supporting the pouring of base mat concrete, which is expected to occur following approval of the license amendment requests in March 2013. Various design and other issues are expected to arise as construction proceeds, which may result in additional license amendments or require other resolution. If any license amendment requests 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, additional delays in the fabrication and assembly of structural modules, the failure of such modules to meet applicable standards, or other issues 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 $107 million in 2012, $141 million in 2011, and $100 million in 2010 and is included in purchased power, affiliates in the statements of income. The Company accounts for SEGCO using the equity method.

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The Company owns undivided interests in Plants Vogtle, Hatch, Wansley, and Scherer in varying amounts jointly with 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 Florida Power Corporation (Progress Energy Florida) jointly own a combustion turbine unit (Intercession City) operated by Progress Energy Florida.

At December 31, 2012, 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%	$3,327	$1,996	$67
Plant Hatch (nuclear)	50.1	1,037	551	49
Plant Wansley (coal)	53.5	801	240	8
Plant Scherer (coal)				
Units 1 and 2	8.4	161	78	77
Unit 3	75.0	1,127	387	28
Rocky Mountain (pumped storage)	25.4	181	116	—
Intercession City (combustion-turbine)	33.3	12	4	1

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 to the financial statements 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 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:

	2012	2011	2010
	(in millions)		
Federal –			
Current	$273	$106	$147
Deferred	370	479	312
	643	585	459
State –			
Current	38	19	(36)
Deferred	7	21	30
	45	40	(6)

Total	$688	$625	$453

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

	2012	2011
	(in millions)	
Deferred tax liabilities –		
Accelerated depreciation	$4,201	$3,687
Property basis differences	757	804
Employee benefit obligations	255	257
Under-recovered fuel costs	—	56
Premium on reacquired debt	77	72
Regulatory assets associated with employee benefit obligations	536	481
Asset retirement obligations	446	299
Other	93	103
Total	6,365	5,759
Deferred tax assets –		
Federal effect of state deferred taxes	142	157
Employee benefit obligations	644	585
Other property basis differences	100	106
Other deferred costs	39	55
Cost of removal obligations	29	40
State tax credit carry forward	86	52
Over-recovered fuel costs	89	—
Unbilled fuel revenue	39	45
Asset retirement obligations	446	299
Other	42	63
Total	1,656	1,402
Total deferred tax liabilities, net	4,709	4,357
Portion included in current assets/(liabilities), net	152	31
Accumulated deferred income taxes	$4,861	$4,388

At December 31, 2012, tax-related regulatory assets were $738 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, 2012, tax-related regulatory liabilities to be credited to customers were $151 million. These liabilities are primarily attributable to deferred taxes previously recognized at rates higher than current enacted tax law and to unamortized investment tax credits. 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 is occurring ratably over the period from April 2012 through December 2013.
In accordance with regulatory requirements, deferred investment tax credits 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 $13 million in 2012, $9 million in 2011, and $13 million in 2010. At December 31, 2012, all investment tax credits available to reduce federal income taxes payable had been utilized, and the Company has $86 million in state investment tax credits that will expire by 2021.
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 to be placed in

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service in 2013). The application of the bonus depreciation provisions in the Tax Relief Act significantly increased deferred tax liabilities related to accelerated depreciation.

Effective Tax Rate

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

	2012	2011	2010
Federal statutory rate	35.0 %	35.0 %	35.0 %
State income tax, net of federal deduction	1.6	1.5	(0.3)
Non-deductible book depreciation	1.2	0.8	1.0
AFUDC equity	(1.0)	(1.9)	(3.6)
Other	(0.1)	(0.5)	(0.2)
Effective income tax rate	36.7 %	34.9 %	31.9 %

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. The increase in the Company's 2011 effective tax rate is primarily the result of decreases in non-taxable AFUDC equity and state tax credits.

Unrecognized Tax Benefits

For 2012, the total amount of unrecognized tax benefits decreased by $24 million, resulting in a balance of $23 million as of December 31, 2012.

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

	2012	2011	2010
	(in millions)		
Unrecognized tax benefits at beginning of year	$47	$237	$181
Tax positions from current periods	3	9	52
Tax positions increase from prior periods	3	—	27
Tax positions decrease from prior periods	(19)	(87)	(23)
Reductions due to settlements	(8)	(112)	—
Reductions due to expired statute of limitations	(3)	—	—
Balance at end of year	$23	$47	$237

The tax positions from current periods for 2012 relate primarily to the tax accounting method change for repairs-generation assets. See "Tax Method of Accounting for Repairs" herein for additional information. The American Jobs Creation Act of 2004 created a tax deduction for a portion of income attributable to U.S. production activities as defined in Section 199 of the Internal Revenue Code (production activities deduction). The tax positions decrease from prior periods and reductions due to settlements for 2012 primarily relate to Georgia's manufacturer's investment tax credits and the production activities deduction.

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 investment tax credits.

The impact on the Company's effective tax rate, if recognized, was as follows:

	2012	2011	2010
	(in millions)		
Tax positions impacting the effective tax rate	$—	$28	$202
Tax positions not impacting the effective tax rate	23	19	35
Balance of unrecognized tax benefits	$23	$47	$237

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.

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Accrued interest for unrecognized tax benefits was as follows:

	2012	2011	2010
	(in millions)		
Interest accrued at beginning of year	$6	$27	$20
Interest reclassified due to settlements	(6)	(24)	—
Interest accrued during the year	—	3	7
Balance at end of year	$—	$6	$27

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 associated with a majority of the Company's unrecognized tax positions will significantly increase or decrease within 12 months. The resolution of the tax accounting method change for repairs - generation assets, as well as the conclusion or settlement of 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 audited and closed all of Southern Company's consolidated federal income tax returns prior to 2009 and has settled its audits of Southern Company's consolidated federal income tax returns for 2009 and 2010 in principle, pending final approval. Additionally, the IRS has audited and closed Southern Company's 2011 consolidated federal income tax return. For tax years 2010 through 2013, Southern Company is a participant in the Compliance Assurance Process of the IRS. The audits for the Company's state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2007.

Tax Method of Accounting for Repairs

Southern Company submitted a tax accounting method change related to the deductibility of repair costs associated with its subsidiaries' generation, transmission, and distribution systems effective for the 2009 consolidated federal income tax return in 2010. In August 2011, the IRS issued a revenue procedure, which provides a safe harbor method of accounting that taxpayers may use to determine eligible repair costs for transmission and distribution property. The IRS continues to work with the utility industry in an effort to define eligible repair costs for generation assets in a consistent manner for all utilities. 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. The utility industry anticipates more detailed guidance concerning these regulations. Due to the uncertainty regarding the ultimate resolution of the repair costs for generation assets, an unrecognized tax position has been recorded for the tax accounting method change for repairs-generation assets. The ultimate outcome of this matter cannot be determined at this time; however, it is not expected to materially impact net income.

6. FINANCING

Securities Due Within One Year

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

	2012	2011
	(in millions)	
Senior notes	$1,675	$200
Capital lease	5	5
Bank term loans	—	250
Total	$1,680	$455

Maturities through 2017 applicable to total long-term debt are as follows: $1.7 billion in 2013; $5 million in 2014; $1.1 billion in 2015; $260 million in 2016; and $456 million in 2017.

Senior Notes

The Company issued $2.3 billion aggregate principal amount of unsecured senior notes in 2012. The proceeds of these issuances were used to repay $850 million of unsecured senior notes and $250 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.

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At December 31, 2012 and 2011, the Company had $7.9 billion and $6.4 billion of senior notes outstanding, respectively. These senior notes are effectively subordinated to all secured debt of the Company, which aggregated $50 million and $55 million at December 31, 2012 and 2011, respectively, and was related to capital lease obligations.

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 both December 31, 2012 and 2011 was $1.8 billion. Proceeds from certain issuances are restricted until qualifying expenditures are incurred.

In 2012, the Company incurred obligations in connection with issuance by public authorities of an aggregate of $284 million of pollution control revenue bonds. The proceeds of these issuances were used to redeem $284 million of outstanding pollution control bonds.

Bank Term Loans

In March 2012, the Company paid at maturity $250 million aggregate principal amount of variable rate long-term bank notes bearing interest at a rate based on one-month London Interbank Offered Rate (LIBOR).

In May 2012, the Company redeemed $200 million aggregate principal amount of variable rate short-term bank notes due June 15, 2012 bearing interest at a rate based on one-month LIBOR.

At December 31, 2011, the Company had $450 million of bank loans outstanding. There were no bank term loans outstanding at December 31, 2012.

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, 2012 and 2011, the Company had a capitalized lease obligation for its corporate headquarters building of $50 million and $55 million, respectively, with an interest rate of 7.9% and 7.4%, respectively. For ratemaking purposes, the Georgia PSC has treated the lease as an operating lease and 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 liquidation amount of the stock. In addition, the Company may redeem the outstanding series of the preference stock at a redemption price equal to 100% of the liquidation amount plus, with respect to any redemption prior to October 1, 2017, 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.

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Bank Credit Arrangements
At December 31, 2012, committed credit arrangements with banks were as follows:

Expires[a]			
2014	2016	Total	Unused
(in millions)			
$250	$1,500	$1,750	$1,740

(a) No credit arrangements expire in 2013 or 2015.

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. In addition, the credit arrangements contain cross default provisions that are restricted only to the indebtedness of the Company. The Company is currently in compliance with all such covenants. None of the arrangements contain material adverse change clauses at the time of borrowings.

A portion of the $1.7 billion of unused credit arrangements provides 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, 2012 was $865 million.

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 loans are included in notes payable on the balance sheets.

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, 2011 were as follows:

	Short-term Debt at the End of the Period[a]	
	Amount Outstanding	Weighted Average Interest Rate
	(in millions)	
December 31, 2011:		
Commercial paper	$313	0.2%
Short-term bank debt	200	1.2%
Total	$513	0.5%

(a) Excludes notes payable related to other energy service contracts of $2 million.

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 2012, 2011, and 2010, the Company incurred fuel expense of $2.1 billion, $2.8 billion, and $3.1 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's 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 $50 million, $52 million, and $55 million in 2012, 2011, and 2010, respectively.

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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 $169 million, $216 million, and $223 million for 2012, 2011, and 2010, respectively. Estimated total long-term obligations at December 31, 2012 were as follows:

Minimum Lease Payments

	Capital Lease PPAs (in millions)	Operating Lease PPAs	Vogtle Units 1 and 2 Capacity Payments	Total ($)
2013	$—	$162	$24	$186
2014	—	165	19	184
2015	22	223	11	256
2016	22	240	11	273
2017	23	215	8	246
2018 and thereafter	301	2,448	69	2,818
Total	$368	$3,453	$142	$3,963
Less: amounts representing executory costs(1)	$55			
Net minimum lease payments	$313			
Less: amounts representing interest(2)	$85			
Present value of net minimum lease payments(3)	$228			

(1) Executory costs include items such as taxes, maintenance, and insurance (including the estimated profit thereon).
(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 a capital lease asset and a capital lease obligation of $149 million, equal to the estimated fair value of the leased property.

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. The credit rating of Southern Power is currently below that of the traditional operating companies. 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 $34 million for 2012, $33 million for 2011, and $35 million for 2010. The Company includes any step rents, fixed escalations, and lease concessions in its computation of minimum lease payments, which are recognized on a straight-line basis over the minimum lease term.

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As of December 31, 2012, estimated minimum lease payments under operating leases were as follows:

	Minimum Lease Payments		
	Railcars	Other	Total
	(in millions)		
2013	$25	$5	$30
2014	20	4	24
2015	14	3	17
2016	8	2	10
2017	5	1	6
2018 and thereafter	2	1	3
Total	$74	$16	$90

A portion of the railcar lease 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 $33 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 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. Alabama Power has also guaranteed $50 million in senior notes issued by SEGCO. 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 stock of SEGCO if Alabama Power is called upon to make such payment under its guaranty.

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, 2012, there were 1,402 current and former employees of the Company participating in the stock option program, and there were 39 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. For certain stock option awards, a change in control will provide accelerated vesting.

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.

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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	2012	2011	2010
Expected volatility	17.7 %	17.5 %	17.4 %
Expected term (in years)	5.0	5.0	5.0
Interest rate	0.9 %	2.3 %	2.4 %
Dividend yield	4.2 %	4.8 %	5.6 %
Weighted average grant-date fair value	$3.39	$3.23	$2.23

The Company's activity in the stock option program for 2012 is summarized below:

	Shares Subject to Option	Weighted Average Exercise Price
Outstanding at December 31, 2011	7,952,587	$33.73
Granted	1,269,725	44.43
Exercised	(2,666,146)	32.77
Cancelled	(8,668)	42.04
Outstanding at December 31, 2012	6,547,498	$36.18
Exercisable at December 31, 2012	4,196,637	$33.96

The number of stock options vested, and expected to vest in the future, as of December 31, 2012 was not significantly different from the number of stock options outstanding at December 31, 2012 as stated above. As of December 31, 2012, 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 $45 million and $37 million, respectively.

As of December 31, 2012, 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, 2012, 2011, and 2010 was $34 million, $32 million, and $12 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises was not material for any of the years presented.

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.

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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	2012	2011	2010
Expected volatility	16.0 %	19.2 %	20.7 %
Expected term (in years)	3.0	3.0	3.0
Interest rate	0.4 %	1.4 %	1.4 %
Annualized dividend rate	$ 1.89	$ 1.82	$ 1.75
Weighted average grant-date fair value	$ 41.99	$ 35.97	$ 30.13

Total unvested performance share units outstanding as of December 31, 2011 were 325,958. During 2012, 152,812 performance share units were granted, 179,917 performance shares were vested, and 18,853 performance share units were forfeited resulting in 280,000 unvested units outstanding at December 31, 2012. In January 2013, the vested performance share award units were converted into 242,938 shares outstanding at a share price of $43.05 for the three-year performance and vesting period ended December 31, 2012.

Total compensation cost for performance share units and the related tax benefit recognized in income were immaterial for all years presented. As of December 31, 2012, the amount of total unrecognized compensation cost related to performance share award units that will be recognized over a weighted-average period of approximately 11 months was immaterial.

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 the Company's Plant Hatch and Plant Vogtle Units 1 and 2. The Act provides funds up to $12.6 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 $117.5 million per incident for each licensed reactor it operates but not more than an aggregate of $17.5 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 $232 million, per incident, but not more than an aggregate of $35 million to be paid for each incident in any one year. See Note 4 to the financial statements herein for additional information on joint ownership agreements.

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 October 29, 2013.

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 policies that currently provide decontamination, excess property insurance, and premature decommissioning coverage up to $2.25 billion for losses in excess of the $500 million primary coverage. This excess insurance is also provided by NEIL.

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 the maximum limit allowed by NEIL, 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 if losses each year exceed the accumulated funds available to the insurer under that policy. The current maximum annual assessments for the Company under the NEIL policies would be $70 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

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additional amounts NEIL can recover through reinsurance, indemnity, or other sources.

For all on-site property damage insurance policies for commercial nuclear power plants, the NRC requires that the proceeds of such policies shall be dedicated first for the sole purpose of placing the reactor in a safe and stable condition after an accident. Any remaining proceeds are to be applied next toward the costs of decontamination and debris removal operations ordered by the NRC, and any further remaining proceeds are to be paid either to the Company or to its debt trustees as may be appropriate under the policies and applicable trust indentures. In the event of a loss, the amount of insurance available might not be adequate to cover property damage and other expenses incurred. Uninsured losses and other expenses, to the extent not recovered from customers, would be borne by the Company and could have a material effect on the Company's financial condition and results of operations.

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

10. FAIR VALUE MEASUREMENTS

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

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

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

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As of December 31, 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.

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As of December 31, 2011, 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, 2011:	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	$—	$13	$—	$13
Nuclear decommissioning trusts:[(a)]				
Domestic equity	143	1	—	144
Foreign equity	100	—	—	100
U.S. Treasury and government agency securities	—	25	—	25
Municipal bonds	—	82	—	82
Corporate bonds	—	167	—	167
Mortgage and asset backed securities	—	123	—	123
Other investments	—	25	—	25
Cash equivalents	13	—	—	13
Total	$256	$436	$—	$692
Liabilities:				
Energy-related derivatives	$—	$95	$—	$95

(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 London Interbank Offered Rate 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)
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As of December 31, 2012 and 2011, 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, 2012:	(in millions)			
Nuclear decommissioning trusts:				
Foreign equity fund	$117	None	Monthly	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
As of December 31, 2011:				
Nuclear decommissioning trusts:				
Corporate bonds — commingled funds	$32	None	Daily	Not applicable
Other — commingled funds	25	None	Daily	Not applicable
Cash equivalents:				
Money market funds	13	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.

NOTES (continued)
Georgia Power Company 2012 Annual Report

As of December 31, 2012 and 2011, 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:		
2012	$9,624	$10,427
2011	$8,418	$9,209

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.

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, 2012, the net volume of energy-related derivative contracts for natural gas positions totaled 105 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 3 million mmBtu for the Company.

NOTES (continued)
Georgia Power Company 2012 Annual Report

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, 2012, there were no interest rate derivatives outstanding.
The estimated pre-tax losses that will be reclassified from OCI to interest expense for the 12-month period ending December 31, 2013 are not expected to have a material impact on the Company's financial statements. The Company has deferred gains and losses related to interest rate derivative settlements that are expected to be amortized into earnings through 2037.

Derivative Financial Statement Presentation and Amounts
At December 31, 2012 and 2011, the fair value of energy-related derivatives was reflected in the balance sheets as follows:

Derivative Category	Asset Derivatives Balance Sheet Location	2012	2011	Liability Derivatives Balance Sheet Location	2012	2011
		(in millions)			(in millions)	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	$6	$8	Liabilities from risk management activities	$30	$68
	Other deferred charges and assets	5	5	Other deferred credits and liabilities	15	27
Total derivatives designated as hedging instruments for regulatory purposes		$11	$13		$45	$95

All derivative instruments are measured at fair value. See Note 10 for additional information.
At December 31, 2012 and 2011, 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	2012	2011	Unrealized Gains Balance Sheet Location	2012	2011
		(in millions)			(in millions)	
Energy-related derivatives:	Other regulatory assets, current	$(30)	$(68)	Other regulatory liabilities, current	$6	$8
	Other regulatory assets, deferred	(15)	(27)	Other deferred credits and liabilities	5	5

Total energy-related derivative gains (losses)	$(45)	$(95)	$11	$13

NOTES (continued)
Georgia Power Company 2012 Annual Report

The pre-tax effects of gains (losses) related to interest rate derivatives designated as cash flow hedging instruments recognized in OCI were not material for any year presented. Gains (losses) reclassified from accumulated OCI into income were as follows:

Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)			
	Amount		
Statements of Income Location	2012	2011	2010
	(in millions)		
Interest expense, net of amounts capitalized	$(3)	$(4)	$(16)

There was no material ineffectiveness recorded in earnings for any period presented. The pre-tax effect of energy-related derivatives not designated as hedging instruments on the statements of income was not material for any year presented.

Contingent Features

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain affiliated companies. At December 31, 2012, the fair value of derivative liabilities with contingent features was $6 million.

At December 31, 2012, 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 $15 million. 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.

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NOTES (continued)
Georgia Power Company 2012 Annual Report

12. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)
Summarized quarterly financial information for 2012 and 2011 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred and Preference Stock
	(in millions)		
March 2012	$1,745	$344	$167
June 2012	2,020	535	295
September 2012	2,498	924	525
December 2012	1,735	400	181
March 2011	$1,989	$393	$206
June 2011	2,265	537	309
September 2011	2,788	895	520
December 2011	1,758	222	110

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

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SELECTED FINANCIAL AND OPERATING DATA 2008-2012
Georgia Power Company 2012 Annual Report

	2012	2011	2010	2009	2008
Operating Revenues (in millions)	$7,998	$8,800	$8,349	$7,692	$8,412
Net Income After Dividends on Preferred and Preference Stock (in millions)	$1,168	$1,145	$950	$814	$903
Cash Dividends on Common Stock (in millions)	$983	$1,096	$820	$739	$721
Return on Average Common Equity (percent)	12.76	12.89	11.42	11.01	13.56
Total Assets (in millions)	$28,803	$27,151	$25,914	$24,295	$22,316
Gross Property Additions (in millions)	$1,838	$1,981	$2,401	$2,646	$1,953
Capitalization (in millions):					
Common stock equity	$9,273	$9,023	$8,741	$7,903	$6,879
Preferred and preference stock	266	266	266	266	266
Long-term debt	7,994	8,018	7,931	7,782	7,006
Total (excluding amounts due within one year)	$17,533	$17,307	$16,938	$15,951	$14,151
Capitalization Ratios (percent):					
Common stock equity	52.9	52.1	51.6	49.5	48.6
Preferred and preference stock	1.5	1.5	1.6	1.7	1.9
Long-term debt	45.6	46.4	46.8	48.8	49.5
Total (excluding amounts due within one year)	100.0	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	2,062,040	2,047,390	2,049,770	2,043,661	2,039,503
Commercial	297,294	296,143	296,140	295,375	295,925
Industrial	8,246	8,279	8,136	8,202	8,248
Other	7,724	7,521	7,309	6,580	5,566
Total	2,375,304	2,359,333	2,361,355	2,353,818	2,349,242
Employees (year-end)	8,094	8,310	8,330	8,599	9,337

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SELECTED FINANCIAL AND OPERATING DATA 2008-2012 (continued)
Georgia Power Company 2012 Annual Report

	2012	2011	2010	2009	2008
Operating Revenues (in millions):					
Residential	$2,986	$3,241	$3,072	$2,686	$2,648
Commercial	2,965	3,217	3,011	2,826	2,917
Industrial	1,322	1,547	1,441	1,318	1,640
Other	89	94	84	82	81
Total retail	7,362	8,099	7,608	6,912	7,286
Wholesale — non-affiliates	281	341	380	395	569
Wholesale — affiliates	20	32	53	112	286
Total revenues from sales of electricity	7,663	8,472	8,041	7,419	8,141
Other revenues	335	328	308	273	271
Total	$7,998	$8,800	$8,349	$7,692	$8,412
Kilowatt-Hour Sales (in millions):					
Residential	25,742	27,223	29,433	26,272	26,412
Commercial	32,270	32,900	33,855	32,593	33,058
Industrial	23,089	23,519	23,209	21,810	24,164
Other	641	657	663	671	671
Total retail	81,742	84,299	87,160	81,346	84,305
Wholesale — non-affiliates	2,934	3,904	4,662	5,208	9,755
Wholesale — affiliates	600	626	1,000	2,504	3,695
Total	85,276	88,829	92,822	89,058	97,755
Average Revenue Per Kilowatt-Hour (cents):					
Residential	11.60	11.91	10.44	10.22	10.03
Commercial	9.19	9.78	8.89	8.67	8.82
Industrial	5.73	6.58	6.21	6.04	6.79
Total retail	9.01	9.61	8.73	8.50	8.64
Wholesale	8.52	8.23	7.65	6.57	6.36
Total sales	8.99	9.54	8.66	8.33	8.33
Residential Average Annual Kilowatt-Hour Use Per Customer	12,509	13,288	14,367	12,848	12,969
Residential Average Annual Revenue Per Customer	$1,451	$1,582	$1,499	$1,314	$1,300
Plant Nameplate Capacity Ratings (year-end) (megawatts)	17,984	16,588	15,992	15,995	15,995
Maximum Peak-Hour Demand (megawatts):					
Winter	14,104	14,800	15,614	15,173	14,221
Summer	16,440	16,941	17,152	16,080	17,270
Annual Load Factor (percent)	59.1	59.5	60.9	60.7	58.4
Plant Availability (percent)*:					
Fossil-steam	90.3	88.6	88.6	92.5	91.0
Nuclear	94.1	92.2	94.0	88.4	89.8
Source of Energy Supply (percent):					
Coal	26.6	44.4	51.8	52.3	58.7

Nuclear	18.3	16.6	16.4	16.2	14.8
Hydro	0.7	1.1	1.4	1.8	0.6
Oil and gas	22.0	8.9	8.0	7.7	5.1
Purchased power -					
From non-affiliates	6.8	6.1	5.2	4.4	5.1
From affiliates	25.6	22.9	17.2	17.6	15.7
Total	100.0	100.0	100.0	100.0	100.0

* Beginning in 2012, plant availability is calculated as a weighted equivalent availability.

GULF POWER COMPANY
FINANCIAL SECTION

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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Gulf Power Company 2012 Annual Report
The management of Gulf Power Company (the Company) is responsible for establishing and maintaining an adequate system of internal control over financial reporting as required by the Sarbanes-Oxley Act of 2002 and as defined in Exchange Act Rule 13a-15(f). A control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met.
Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in Internal Control—Integrated Framework 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, 2012.
/s/ S. W. Connally, Jr.
S. W. Connally, Jr.
President and Chief Executive Officer
/s/ Richard S. Teel
Richard S. Teel
Vice President and Chief Financial Officer
February 27, 2013

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM
To the Board of Directors of
Gulf Power Company

We have audited the accompanying balance sheets and statements of capitalization of Gulf Power Company (the Company) (a wholly owned subsidiary of The Southern Company) as of December 31, 2012 and 2011, 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, 2012. 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-311 to II-351) present fairly, in all material respects, the financial position of Gulf Power Company as of December 31, 2012 and 2011, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 27, 2013

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Gulf Power Company 2012 Annual Report
OVERVIEW
Business Activities
Gulf Power Company (the Company) operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located in northwest Florida and to wholesale customers in the Southeast.
Many factors affect the opportunities, challenges, and risks of the Company's business of 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, storm restoration following major storms, and fuel. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future.
On March 12, 2012, the Florida Public Service Commission (PSC) approved an increase in retail base rates and charges of $64 million effective April 11, 2012. The amount of the increase includes the previously approved $38.5 million interim retail rate increase implemented in September 2011. The Florida PSC's decision on the amount of the increase also included a determination that none of the base rate revenues collected on an interim basis would be refunded. The Company's authorized retail return on equity (ROE) is a range of 9.25% to 11.25% with new retail base rates set at the midpoint retail ROE of 10.25%. In addition, the Florida PSC also approved a step increase to the Company's retail base rates and charges of $4 million effective in January 2013.
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 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 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 2012 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 transmission system performance for 2012 did not meet the target for these reliability measures. The distribution system performance for 2012 was better than the target for these reliability measures.
Net income after dividends on preference stock is the primary measure of the Company's financial performance. The Company's 2012 results compared with its targets for some of these key indicators are reflected in the following chart:

Key Performance Indicator	2012 Target Performance	2012 Actual Performance
Customer Satisfaction	Top quartile in customer surveys	Top quartile
Peak Season EFOR	4.99% or less	0.67%
Net Income After Dividends on Preference Stock	$120.7 million	$125.9 million

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance. The performance achieved in 2012 reflects the continued emphasis the Company places on reliability, customer satisfaction, and financial integrity, as well as the commitment shown by employees in achieving or exceeding management's expectations.
Earnings

The Company's 2012 net income after dividends on preference stock was $125.9 million, an increase of $20.9 million from the previous year. The increase in net income after dividends on preference stock in 2012 was primarily due to higher revenues due to increases in retail base rates and higher wholesale capacity revenues from non-affiliates in 2012. These increases were partially offset by milder weather in 2012, a decrease in retail energy sales in 2012 due to a decrease in customer usage, and a decrease in allowance for funds used during construction (AFUDC) equity, which is non-taxable.

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Gulf Power Company 2012 Annual Report

In 2011, net income after dividends on preference stock was $105.0 million, a decrease of $16.5 million from the previous year. The decrease in net income after dividends on preference stock in 2011 was primarily due to an increase in other operations and maintenance expenses in 2011 and closer to normal weather in 2011 compared to 2010, partially offset by higher wholesale capacity revenues from non-affiliates.

RESULTS OF OPERATIONS

A condensed statement of income follows:

	Amount	Increase (Decrease) from Prior Year	
	2012	2012	2011
	(in millions)		
Operating revenues	$1,439.7	$(80.1)	$(70.4)
Fuel	544.9	(117.4)	(80.0)
Purchased power	74.1	(16.4)	(6.7)
Other operations and maintenance	314.2	2.8	30.7
Depreciation and amortization	141.0	11.4	8.2
Taxes other than income taxes	97.3	(3.9)	(0.5)
Total operating expenses	1,171.5	(123.5)	(48.3)
Operating income	268.2	43.4	(22.1)
Total other income and (expense)	(56.9)	(4.6)	(4.6)
Income taxes	79.2	17.9	(10.2)
Net income	132.1	20.9	(16.5)
Dividends on preference stock	6.2	—	—
Net income after dividends on preference stock	$125.9	$20.9	$(16.5)

Operating Revenues

Operating revenues for 2012 were $1.44 billion, reflecting a decrease of $80.1 million from 2011. The following table summarizes the significant changes in operating revenues for the past two years:

	Amount	
	2012	2011
	(in millions)	
Retail — prior year	$1,208.5	$1,308.7
Estimated change in –		
Rates and pricing	62.7	2.0
Sales growth (decline)	(5.5)	3.9
Weather	(10.7)	(17.8)
Fuel and other cost recovery	(110.5)	(88.3)
Retail — current year	1,144.5	1,208.5
Wholesale revenues –		
Non-affiliates	106.9	133.6
Affiliates	123.6	111.3
Total wholesale revenues	230.5	244.9
Other operating revenues	64.7	66.4
Total operating revenues	$1,439.7	$1,519.8
Percent change	(5.3)%	(4.4)%

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Gulf Power Company 2012 Annual Report

Retail revenues decreased $64.0 million, or 5.3%, in 2012 compared to 2011 primarily as a result of lower fuel revenues due to lower natural gas prices and lower energy sales due to milder weather in 2012 compared to 2011, partially offset by higher revenues resulting from increases in retail base rates. Retail revenues decreased $100.2 million, or 7.7%, in 2011 compared to 2010 primarily as a result of lower fuel revenues and lower energy sales due to closer to normal weather in 2011 compared to 2010, partially offset by an increase related to interim retail rate revenues. See "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales growth (or decline) and weather.

Revenues associated with changes in rates and pricing include higher revenues due to increases in retail base rates and revenues associated with higher recoverable costs under the Company's energy conservation cost recovery clause, partially offset by a decrease in revenues associated with lower recoverable costs under the Company's environmental cost recovery clause. Annually, the Company petitions the Florida PSC for recovery of projected costs, including any true-up amount from prior periods, and approved rates are implemented each January. The recovery provisions include related expenses and a return on average net investment.

Fuel and other cost recovery provisions include fuel expenses, the energy component of purchased power costs, purchased power capacity costs, and the difference between projected and actual costs and revenues related to energy conservation and environmental compliance. Annually, the Company petitions the Florida PSC for recovery of projected fuel and purchased power costs, including any true-up amount from prior periods, and approved rates are implemented each January. The recovery provisions generally equal the related expenses and have no material effect on earnings.

See Note 1 to the financial statements under "Revenues" and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information regarding the Company's retail base rate case and cost recovery clauses, including the Company's fuel cost recovery, purchased power capacity recovery, environmental cost recovery, and energy conservation cost recovery clauses.

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

	2012	2011	2010
	(in thousands)		
Unit power sales –			
Capacity	$56,379	$52,507	$33,482
Energy	16,520	44,227	31,379
Total	72,899	96,734	64,861
Other power sales –			
Capacity and other	11,795	10,717	11,158
Energy	22,187	26,104	33,153
Total	33,982	36,821	44,311
Total non-affiliated	$106,881	$133,555	$109,172

Wholesale revenues from sales to non-affiliates include unit power sales under long-term contracts to other utilities in Florida and Georgia. Wholesale revenues from contracts have both capacity and energy components. Capacity revenues reflect the recovery of fixed costs and a return on investment. Energy is generally sold at variable cost. Wholesale revenues from non-affiliates will vary depending on fuel prices, the market prices of wholesale energy compared to the cost of the Company 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.

Revenues from unit power sales decreased $23.8 million, or 24.6%, in 2012 primarily due to a 62.6% decrease in energy revenues resulting from a 65.2% decrease in kilowatt-hour (KWH) sales as a result of less energy scheduled by unit power customers due to their use of lower cost generation resources to serve their loads, partially offset by a 7.4% increase in capacity revenues related to higher capacity rates. These contracts include change-in-law provisions that provide for recovery of the environmental costs related to the generating resource. Revenues from other power sales decreased $2.8 million, or 7.7%, in 2012 primarily due to decreased energy revenues resulting from a 16.5% decrease in energy rates, partially offset by a 10.1% increase in capacity revenues related to higher capacity rates. Revenues from unit power sales increased $31.9 million, or 49.1%, in 2011 primarily due to a 56.8% increase in capacity revenues related to higher capacity rates as a result of contracts effective in 2010. The increase in unit power sales was also due to increased energy revenues related to a 31.3% increase in KWH sales. Revenues from other power sales decreased $7.5 million, or 16.9%, in 2011 primarily due to decreased energy revenues related to a 9.6% decrease in KWH sales.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Gulf Power Company 2012 Annual Report

Wholesale revenues from sales to affiliated companies will vary from year to year depending on demand and the availability and cost of generating resources at each company. These affiliated 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 the fuel revenue related to energy sales and the cost of energy purchases are both included in the determination of recoverable fuel costs and are generally offset by revenues collected in the Company's fuel cost recovery clause. In 2012, wholesale revenues from sales to affiliates increased $12.3 million from the prior period primarily due to higher energy revenues related to a 67.6% increase in KWH sales resulting from the availability of the Company's lower priced generation resources to serve affiliate demand, partially offset by a 33.8% decrease in the price of energy in 2012. In 2011, wholesale revenues from sales to affiliates increased $1.3 million from the prior period primarily due to higher energy revenues related to a 7.0% increase in KWH sales resulting from the availability of the Company's lower priced generation resources to serve affiliate demand, partially offset by a 5.2% decrease in the price of energy in 2011.

Other operating revenues decreased $1.7 million, or 2.5%, in 2012 primarily due to a $3.0 million decrease in franchise fees, partially offset by a $2.0 million increase in revenues from other energy services. Other operating revenues increased $4.1 million, or 6.7%, in 2011 primarily due to a $3.4 million increase in revenues from other energy services. Revenues from other energy services did not have a material effect on net income since they were generally offset by associated expenses. Franchise fees have no impact on net income.

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2012 and the percent change by year were as follows:

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2012	2012	2011	2012	2011
	(in millions)				
Residential	5,054	(4.7)%	(6.1)%	(0.2)%	0.5%
Commercial	3,859	(1.4)	(2.1)	(0.5)	—
Industrial	1,725	(4.1)	6.7	(4.1)	6.7
Other	25	(0.6)	(0.7)	(0.6)	(0.7)
Total retail	10,663	(3.4)	(2.8)	(0.9)%	1.3%
Wholesale					
Non-affiliates	977	(51.5)	20.2		
Affiliates	4,370	67.6	7.0		
Total wholesale	5,347	15.7	12.4		
Total energy sales	16,010	2.2%	1.2%		

Changes in retail energy sales are comprised of changes in electricity usage by customers, changes in weather, and changes in the number of customers.

Residential KWH sales and commercial KWH sales decreased in 2012 compared to 2011 primarily due to milder weather in 2012 compared to 2011. Weather-adjusted 2012 KWH sales to residential and commercial customers remained relatively flat as compared to 2011. Residential KWH sales and commercial KWH sales decreased in 2011 compared to 2010 primarily due to closer to normal weather in 2011 compared to 2010. Weather-adjusted 2011 KWH sales to residential and commercial customers remained relatively flat as compared to 2010.

Industrial KWH sales decreased 4.1% in 2012 compared to 2011 primarily due to increased customer co-generation due to the lower cost of natural gas and changes in customer production levels. Industrial KWH sales increased 6.7% in 2011 compared to 2010 primarily resulting from the addition of a new large customer and higher customer load requirements and production levels.

Wholesale KWH sales to non-affiliates decreased 51.5% in 2012 compared to 2011 primarily resulting from less energy scheduled by unit power customers due to their use of lower cost generation resources to serve their loads. Wholesale KWH sales to non-affiliates increased 20.2% in 2011 compared to 2010 primarily resulting from higher KWHs scheduled by unit power customers.

Wholesale KWH sales to affiliates increased 67.6% and 7.0% in 2012 and 2011, respectively, compared to the prior periods primarily resulting from the availability of the Company's lower priced generation resources to serve affiliate demand.

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.

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

	2012	2011	2010
Total generation (millions of KWHs)	9,648	12,035	13,440
Total purchased power (millions of KWHs)	6,952	4,349	2,858
Sources of generation (percent) –			
Coal	60	67	78
Gas	40	33	22
Cost of fuel, generated (cents per net KWH) –			
Coal	4.42	4.97	5.10
Gas	3.96	4.06	4.68
Average cost of fuel, generated (cents per net KWH)	4.23	4.67	5.01
Average cost of purchased power (cents per net KWH*)	3.03	4.39	5.82

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

Total fuel and purchased power expenses were $619.0 million in 2012, a decrease of $133.8 million, or 17.8%, from the prior year costs. The decrease in fuel and purchased power expenses was due to a $129.9 million decrease in the average cost of fuel and purchased power and a $118.2 million decrease related to the volume of KWHs generated. The decrease was partially offset by a $114.3 million increase related to the volume of KWHs purchased. Total fuel and purchased power expenses were $752.8 million in 2011, a decrease of $86.7 million, or 10.3%, from the prior year costs. The decrease in fuel and purchased power expenses was due to a $103.2 million decrease in the average cost of fuel and purchased power and a $70.3 million decrease related to KWHs generated, partially offset by an $86.8 million increase related to KWHs purchased.

From an overall global market perspective, coal prices decreased from levels experienced in 2011 due to lower demand. In the U.S., this decrease was due primarily to relatively lower domestic natural gas prices that contributed to displacement of coal generation by natural gas-fueled generating units. Lower domestic natural gas prices in 2012 were driven by continued robust supplies, including production from shale gas, and only modest increases in overall U.S. consumption.

Fuel and purchased power transactions do not have a significant impact on earnings since energy and capacity expenses are generally offset by energy and capacity revenues through the Company's fuel cost and purchased power capacity recovery clauses. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" and "– Purchased Power Capacity Recovery" herein for additional information.

Fuel

Fuel expense was $544.9 million in 2012, a decrease of $117.4 million, or 17.7%, from the prior year costs. The decrease was primarily due to a higher utilization of lower cost natural gas-fired sources, a 2.5% decrease in the average cost of natural gas per KWH generated, and a 19.8% decrease in KWHs generated as a result of displacement of coal-fired generation by energy purchases and lower demand related to milder weather. These decreases were partially offset by a 59.8% increase in KWHs purchased. Fuel expense was $662.3 million in 2011, a decrease of $80.0 million, or 10.8%, from the prior year costs. The decrease was primarily the result of a 13.3% decrease in the average cost of natural gas per KWH generated, a change in the source of generation to be more heavily weighted to lower cost, natural gas-fired generation, and a 10.5% decrease in KWHs generated as a result of lower demand. These decreases were partially offset by a 52.2% increase in KWHs purchased.

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Purchased Power – Non-Affiliates
Purchased power expense from non-affiliates was $51.4 million in 2012, an increase of $2.5 million, or 5.2%, from the prior year. The increase was due to a $2.7 million increase in energy costs, partially offset by a $0.2 million decrease in capacity costs. The increase in energy costs was due to an increase in the volume of KWHs purchased, partially offset by a lower average cost per KWH. In 2011, purchased power expense from non-affiliates was $48.9 million, an increase of $7.6 million, or 18.4%, from the prior year. The increase was due to a $7.2 million increase in energy costs and a $0.4 million increase in capacity costs.
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 $22.7 million in 2012, a decrease of $18.9 million, or 45.5%, from the prior year. The decrease was due to a $19.1 million decrease in energy costs, partially offset by a $0.2 million increase in capacity costs. The decrease in energy costs was due to a decrease in the volume of KWHs purchased and a lower cost per KWH purchased. In 2011, purchased power expense from affiliates was $41.6 million, a decrease of $14.3 million, or 25.6%, from the prior year. The decrease was due to decreases of $9.0 million in energy costs and $5.3 million in capacity costs.
Energy purchases from affiliates will vary depending on 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 2012, other operations and maintenance expenses increased $2.8 million, or 0.9%, compared to the prior year primarily due to increases of $6.2 million in marketing programs and $3.0 million for transmission service related to a third party power purchase agreement (PPA), partially offset by a $6.9 million decrease in routine and planned outage maintenance expense at generation facilities. The increased expense from transmission service did not have a significant impact on earnings since the expense was offset by purchased power capacity revenues through the Company's purchased power capacity recovery clause. The increased expense from marketing programs did not have a significant impact on earnings since the expense was offset by energy conservation revenues through the Company's energy conservation cost recovery clause. In 2011, other operations and maintenance expenses increased $30.7 million, or 11.0%, compared to the prior year primarily due to increases of $13.9 million in routine and planned outage maintenance expense at generation facilities, $3.2 million in other energy services, $10.4 million in labor expense, and $2.1 million in marketing programs. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Cost Recovery Clauses – Purchased Power Capacity Recovery" and "–Energy Conservation Cost Recovery" herein and Note 1 to the financial statements under "Affiliate Transactions" for additional information.
Depreciation and Amortization
Depreciation and amortization increased $11.4 million, or 8.8%, in 2012 compared to the prior year primarily due to the addition of environmental control projects at generation facilities and other net additions to transmission and distribution facilities. Depreciation and amortization increased $8.2 million, or 6.7%, in 2011 compared to the prior year primarily due to the addition of environmental control projects at generation facilities and other net additions to transmission and distribution facilities.
Taxes Other Than Income Taxes
Taxes other than income taxes decreased $3.9 million, or 3.9%, in 2012 compared to the prior year primarily due to a $6.1 million decrease in gross receipts taxes and franchise fees, partially offset by a $1.3 million increase in property taxes and a $0.7 million increase in payroll taxes. Taxes other than income taxes decreased $0.5 million, or 0.5%, in 2011 compared to the prior year primarily due to a $1.1 million decrease in gross receipts taxes, partially offset by a $0.7 million increase in property taxes. Gross receipts taxes and franchise fees have no impact on net income.

Allowance for Funds Used During Construction Equity

Allowance for funds used during construction (AFUDC) equity decreased $4.7 million, or 47.3%, in 2012 compared to the prior year primarily due to an adjustment related to deferred future generation carrying costs and the completion of construction projects related to environmental control projects at generation facilities. AFUDC equity increased $2.7 million, or 37.4%, in 2011 compared to the prior year primarily due to construction of environmental control projects at generation facilities. See Note 1 to the financial statements under "Allowance for Funds Used During Construction" for additional information.

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Interest Expense, Net of Amounts Capitalized

Interest expense, net of amounts capitalized increased $2.1 million, or 3.6%, in 2012 compared to the prior year primarily due to increases in long-term debt levels. Interest expense, net of amounts capitalized increased $6.3 million, or 12.0%, in 2011 compared to the prior year primarily due to increases in long-term debt levels resulting from the issuance of additional senior notes in 2011. The increase was partially offset as a result of an increase in capitalization of AFUDC debt related to the construction of environmental control projects.

Income Taxes

Income taxes increased $17.9 million, or 29.3%, in 2012 compared to the prior year primarily due to higher pre-tax earnings, a reduction in the tax benefits associated with a decrease in AFUDC equity, which is non-taxable, and a decrease in state tax credits. Income taxes decreased $10.2 million, or 14.3%, in 2011 compared to the prior year primarily due to lower pre-tax earnings. See Note 5 to the financial statements under "Effective Tax Rate" 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 in northwest Florida and to wholesale customers in the Southeast. Prices for electricity provided by the Company to retail customers are set by the Florida PSC under cost-based regulatory principles. Prices for wholesale electricity sales, interconnecting transmission lines, and the exchange of electric power are regulated by the FERC. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – 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. 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 neighboring 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 economic conditions impact sales for the Company, and 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

In 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including Alabama Power Company (Alabama Power) and Georgia Power Company (Georgia Power), alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. The EPA alleged NSR violations at five coal-fired generating facilities operated by Alabama Power and three coal-fired generating facilities operated by Georgia Power, including a unit co-owned by the Company. The civil action sought penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. These actions were filed concurrently with the issuance of notices of violation of the NSR provisions to the Company with respect to the Company's Plant Crist. The case against Georgia Power (including claims related to the unit co-owned by the Company) was administratively closed in 2001 and has not been reopened. After Alabama Power was dismissed from the original action, the EPA filed a separate action in 2001 against Alabama Power in the U.S. District Court for the Northern District of Alabama.

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.

Climate Change Litigation

Kivalina Case

In 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs allege that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that some of the defendants (including Southern Company) acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. In 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case. On September 21, 2012, the U.S. Court of Appeals for the Ninth Circuit upheld the U.S. District Court for the Northern District of California's dismissal of the case. On November 27, 2012, the U.S. Court of Appeals for the Ninth Circuit denied the plaintiffs' request for review of the decision. On February 25, 2013, the plaintiffs filed a petition for writ of certiorari with the U.S. Supreme Court. Southern Company believes that these claims are without merit. The ultimate outcome of this matter cannot be determined at this time.

Hurricane Katrina Case

In 2005, immediately following Hurricane Katrina, a lawsuit was filed in the U.S. District Court for the Southern District of Mississippi by Ned Comer on behalf of Mississippi residents seeking recovery for property damage and personal injuries caused by Hurricane Katrina. In 2006, the plaintiffs amended the complaint to include Southern Company and many other electric utilities, oil companies, chemical companies, and coal producers. The plaintiffs allege that the defendants contributed to climate change, which contributed to the intensity of Hurricane Katrina. In 2007, the U.S. District Court for the Southern District of Mississippi dismissed the case. On appeal to the U.S. Court of Appeals for the Fifth Circuit, a three-judge panel reversed the U.S. District Court for the Southern District of Mississippi, holding that the case could proceed, but on rehearing, the full U.S. Court of Appeals for the Fifth Circuit dismissed the plaintiffs' appeal, resulting in reinstatement of the decision of the U.S. District Court for the Southern District of Mississippi in favor of the defendants. In May 2011, the plaintiffs filed an amended version of their class action complaint, arguing that the earlier dismissal was on procedural grounds and under Mississippi law the plaintiffs have a right to re-file. The amended complaint was also filed against numerous chemical, coal, oil, and utility companies, including the Company. On March 20, 2012, the U.S. District Court for the Southern District of Mississippi dismissed the plaintiffs' amended complaint. On April 16, 2012, the plaintiffs appealed the case to the U.S. Court of Appeals for the Fifth Circuit. The Company believes that these claims are without merit. The ultimate outcome of this matter cannot be determined at this time.

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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 2012, the Company had invested approximately $1.4 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $70 million, $141 million, and $136 million for 2012, 2011, and 2010, respectively. The Company expects that base level capital expenditures to comply with existing statutes and regulations, including capital expenditures and compliance costs associated with the EPA's final Mercury and Air Toxics Standards (MATS) rule, will be a total of approximately $644 million from 2013 through 2015, with annual totals of approximately $158 million, $319 million, and $167 million for 2013, 2014, and 2015, respectively.
The Company continues to monitor the development of the EPA's proposed water and coal combustion byproducts 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 byproducts rules for 2013 through 2015. The ultimate capital expenditures and compliance costs with respect to these proposed rules, including additional expenditures required after 2015, 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 Byproducts" 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.
The State of Florida has statutory provisions that allow a utility to petition the Florida PSC for recovery of prudent environmental compliance costs that are not being recovered through base rates or any other recovery mechanism. The environmental cost recovery mechanism in Florida is discussed in Note 3 to the financial statements under "Retail Regulatory Matters – Environmental Cost Recovery." Substantially all of the costs for the Clean Air Act and other new environmental legislation discussed below are expected to be recovered through the environmental cost recovery clause.
Compliance with any new federal or state legislation or regulations relating to air quality, water, coal combustion byproducts, 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 $1.1 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 air quality standard. In 2008, the EPA adopted a more stringent eight-hour ozone National Ambient Air Quality Standard, which it began to implement in September 2011. On May 21, 2012, the EPA published its final determination of nonattainment areas based on the 2008 eight-hour ozone air quality standards. No areas within the Company's service territory were determined to be in nonattainment of this standard.

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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 National Ambient Air Quality 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 National Ambient Air Quality Standard for sulfur dioxide (SO_2), including the establishment of a new one-hour standard, became effective in 2010. The EPA plans to issue area designations under this new standard in June 2013, and areas within the Company's service territory could ultimately be designated as nonattainment. Implementation of the revised SO_2 standard could require additional reductions in SO_2 emissions and increased compliance and operational costs.

Revisions to the National Ambient Air Quality Standard for nitrogen dioxide (NO_2), which established a new one-hour standard, became effective in 2010. On February 29, 2012, the new NO_2 standard became effective. The EPA designated the entire country as "unclassifiable/attainment" under the new standard, with no nonattainment areas designated. However, the new NO_2 standard could result in significant additional compliance and operational costs for units that require new source permitting.

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 August 2011, the EPA adopted the Cross State Air Pollution Rule (CSAPR) to replace CAIR effective January 1, 2012. However, in December 2011, the U. S. Court of Appeals for the District of Columbia Circuit stayed the rule and, on August 21, 2012, vacated CSAPR in its entirety and directed the EPA to continue to administer CAIR pending the EPA's development of a valid replacement. On January 24, 2013, the U.S. Court of Appeals for the District of Columbia Circuit denied requests by the EPA and other parties for rehearing.

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 (BART) 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 2005, the EPA determined that compliance with CAIR satisfies BART obligations under CAVR, but, on June 7, 2012, the EPA issued a final rule replacing CAIR with CSAPR as an alternative means of satisfying BART obligations. The vacatur of CSAPR creates additional uncertainty with respect to whether additional controls may be required for CAVR and BART compliance.

On February 16, 2012, the EPA published the final 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, unless a one-year compliance extension is granted by the state or local air permitting agency. Mississippi Power Company (Mississippi Power) has received this one-year extension for Plant Daniel to April 16, 2016.

Numerous petitions for administrative reconsideration of the MATS rule, including a petition by the Company, have been filed with the EPA. On November 30, 2012, the EPA proposed a reconsideration of certain new source and startup/shutdown issues. The EPA plans to complete its reconsideration rulemaking by March 2013. Challenges to the final rule have also been filed in the U.S. District Court for the District of Columbia by numerous states, environmental organizations, industry groups, and others.

On August 29, 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 Florida, Georgia, and Mississippi) 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. If finalized as proposed, this new requirement could result in significant additional compliance and operational costs.

The Company has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the existing and new environmental requirements discussed above. The impacts of the eight-hour ozone, fine particulate matter, SO_2 and NO_2 standards, 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, certain units in the State of Georgia, including Plant Scherer Unit 3, which is co-owned by the Company, are required to install specific emissions controls according to a schedule set forth in the state's Multi-Pollutant Rule, which is designed to reduce emissions of SO_2, NO_x, and mercury.

See Note 3 to the financial statements under "Retail Regulatory Matters – Environmental Cost Recovery" for discussion of the State of Florida's statutory provisions on environmental cost recovery.

Water Quality

In April 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 has entered into an amended settlement agreement to extend the deadline for issuing a final rule until June 27, 2013. If finalized as proposed, some of the Company's facilities may be subject to 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. The ultimate outcome of this rulemaking will depend on the final rule and the outcome of any legal challenges and cannot be determined at this time.

The EPA has announced its determination that revision of the current effluent guidelines for steam electric power plants is warranted and has stated that it intends to propose such revisions by April 2013 and finalize the revisions by May 2014. New advanced wastewater treatment requirements are expected and may result in the installation of additional controls on certain of the Company's facilities, which could result in significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. The impact of the revised guidelines will depend on the specific technology requirements of the final rule and, therefore, cannot be determined at this time.

In addition, the State of Florida is finalizing numeric nutrient water quality standards to limit the amount of nitrogen and phosphorous allowed in state waters. The impact of these standards will depend on the specific requirements of the final rule and cannot be determined at this time. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" for additional information regarding estimated compliance costs for 2013 through 2015. See also Note 3 to the financial statements under "Retail Regulatory Matters – Environmental Cost Recovery" for discussion of the State of Florida's statutory provisions on environmental cost recovery.

Coal Combustion Byproducts

The Company currently operates three electric generating plants in Florida and is part owner of units at generating plants located in Mississippi and Georgia operated by the respective unit's co-owner with on-site coal combustion byproducts storage facilities. In addition to on-site storage, the Company sells a portion of its coal combustion byproducts to third parties for beneficial reuse. Historically, individual states have regulated coal combustion byproducts and the States of Florida, Georgia, and Mississippi each has its own regulatory parameters. 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 byproducts, 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 byproducts: 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 byproducts 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 byproducts.

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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 byproducts could have a material impact on the generation, management, beneficial use, and disposal of such byproducts. 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. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein for additional information regarding estimated compliance costs for 2013 through 2015. See also Note 3 to the Financial Statements under "Retail Regulatory Matters – Environmental Cost Recovery" for discussion of the State of Florida's statutory provisions on environmental cost recovery.

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. Included in this amount are costs associated with remediation of the Company's substation sites. These projects have been approved by the Florida PSC for recovery through the environmental cost recovery clause; therefore, there is no impact to the Company's net income as a result of these liabilities. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Note 3 to the financial statements under "Environmental Matters – Environmental Remediation" for additional information.

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. 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 April 13, 2012, the EPA published proposed regulations to establish standards of performance for greenhouse gas emissions from new fossil fuel steam electric generating units. The EPA has also announced plans to develop federal guidelines for states to establish greenhouse gas emissions performance standards for existing sources. The impact of this rulemaking will depend on the scope and specific requirements of the final rule and the outcome of any legal challenges and, therefore, cannot be determined at this time.

Although the outcome of federal, state, and international initiatives 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 a significant number of coal-fired generating units. See Item 1 – BUSINESS – "Rate Matters – Integrated Resource Planning" of the Form 10-K for additional information.

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. See Note 3 to the financial statements under "Retail Regulatory Matters – Environmental Cost Recovery" for discussion of the State of Florida's statutory provisions on environmental cost recovery.

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 reported 2011 greenhouse gas emissions of approximately 11 million metric tons of carbon dioxide equivalent. The preliminary estimate of the Company's 2012 greenhouse gas emissions on the same basis is approximately 8 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, which is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units.

PSC Matters

The Company's rates and charges for service to retail customers are subject to the regulatory oversight of the Florida PSC. The Company's rates are a combination of base rates and several separate cost recovery clauses for specific categories of costs. These

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separate cost recovery clauses address such items as fuel and purchased energy costs, purchased power capacity costs, energy conservation and demand side management programs, and the costs of compliance with environmental laws and regulations. Costs not addressed through one of the specific cost recovery clauses are recovered through the Company's base rates.

Retail Base Rate Case

On March 12, 2012, the Florida PSC approved an increase in retail base rates and charges of $64 million effective April 11, 2012. The amount of the increase includes the previously approved $38.5 million interim retail rate increase implemented in September 2011. The Florida PSC's decision on the amount of the increase also included a determination that none of the base rate revenues collected on an interim basis would be refunded. The Company's authorized retail ROE is a range of 9.25% to 11.25% with new retail base rates set at the midpoint retail ROE of 10.25%. In addition, the Florida PSC also approved a step increase to the Company's retail base rates and charges of $4 million effective in January 2013.

Cost Recovery Clauses

On November 5, 2012, the Florida PSC approved the Company's annual rate clause requests for its fuel, purchased power capacity, conservation, and environmental compliance cost recovery factors for 2013. The net effect of the approved changes is a 1.9% rate increase for residential customers using 1,000 KWHs per month.

Revenues for all cost recovery clauses, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor for fuel and purchased power will have no significant effect on the Company's revenues or net income, but will affect annual cash flow. The recovery provisions for environmental compliance and energy conservation include related expenses and a return on net average investment. See Notes 1 and 3 to the financial statements under "Revenues" and "Retail Regulatory Matters" respectively, for additional information.

Fuel Cost Recovery

The Company has established fuel cost recovery rates as approved by the Florida PSC. If, at any time during the year, the projected year-end fuel cost over or under recovery balance exceeds 10% of the projected fuel revenue applicable for the period, the Company is required to notify the Florida PSC and indicate if an adjustment to the fuel cost recovery factor is being requested. On February 14, 2012, the Florida PSC approved a reduction to the fuel cost recovery factors starting in March 2012. The effect of the approved change was a 2.7% decrease for residential customers using 1,000 KWHs per month. On June 19, 2012, the Florida PSC approved an additional decrease in the Company's fuel rates lowering the 1,000 KWH residential bill 7.8% to reduce annual billings by approximately $58.8 million effective July 2, 2012.

The increase in the fuel cost over recovered balance during 2012 was primarily due to lower than expected fuel costs and purchased power energy expenses. At December 31, 2012 and 2011, the over recovered fuel balance was approximately $17.1 million and $9.9 million, respectively, which is included in other regulatory liabilities, current in the balance sheets. See Note 1 to the financial statements under "Fuel Costs" and "Fuel Inventory" for additional information.

Purchased Power Capacity Recovery

The Company has established purchased power capacity recovery cost rates as approved by the Florida PSC. If the projected year-end purchased power capacity cost over or under recovery balance exceeds 10% of the projected purchased power capacity revenue applicable for the period, the Company is required to notify the Florida PSC and indicate if an adjustment to the purchased power capacity cost recovery factor is being requested.

At December 31, 2012, the Company had an under recovered purchased power capacity balance of approximately $0.8 million, which is included in under recovered regulatory clause revenues in the balance sheets. At December 31, 2011, the Company had an over recovered purchased power capacity balance of approximately $8.0 million, which is included in other regulatory liabilities, current in the balance sheets. See Note 7 to the financial statements under "Fuel and Purchased Power Commitments" for additional information.

Environmental Cost Recovery
The Florida Legislature adopted legislation for an environmental cost recovery clause, which allows an electric utility to petition the Florida PSC for recovery of prudent environmental compliance costs that are not being recovered through base rates or any other recovery mechanism. Such environmental costs include operations and maintenance expenses, emissions allowance expense, depreciation, and a return on net average investment. This legislation also allows recovery of costs incurred as a result of an agreement between the Company and the Florida Department of Environmental Protection for the purpose of ensuring compliance with ozone ambient air quality standards adopted by the EPA.

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In 2007, the Florida PSC voted to approve a stipulation among the Company, the Office of Public Counsel, and the Florida Industrial Power Users Group regarding the Company's plan for complying with certain federal and state regulations addressing air quality. The Company's environmental compliance plan as filed in 2007 contemplated implementation of specific projects identified in the plan from 2007 through 2018. The stipulation covers all elements of the original plan that were committed for implementation at the time of the stipulation. The Florida PSC's approval of the stipulation also required the Company to file annual updates to the plan and outlined a process for approval of additional elements in the plan when they became committed projects. In the 2010 update filing, the Company identified several elements of the updated plan that the Company had decided to implement. Following the process outlined in the original approved stipulation, these additional projects were approved by the Florida PSC later in 2010. The Florida PSC acknowledged that the costs of the approved projects associated with the Company's CAIR and CAVR compliance plans are eligible for recovery through the environmental cost recovery clause.

Annually, the Company seeks recovery of projected costs including any true-up amounts from prior periods. At December 31, 2012, the under recovered environmental balance was approximately $1.9 million, which is included in under recovered regulatory clause revenues in the balance sheets. At December 31, 2011, the over recovered environmental balance was approximately $10.0 million, which is included in other regulatory liabilities, current in the balance sheets. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein for additional information.

On April 3, 2012, the Mississippi PSC approved Mississippi Power's request for a certificate of public convenience and necessity to construct a flue gas desulfurization system (scrubber) on Plant Daniel Units 1 and 2. On May 3, 2012, the Sierra Club filed a notice of appeal of the order with the Chancery Court of Harrison County, Mississippi. These units are jointly owned by Mississippi Power and the Company, with 50% ownership each. The estimated total cost of the project is approximately $660 million, excluding AFUDC, and it is scheduled for completion in December 2015. The Company's portion of the cost is expected to be recovered through the environmental cost recovery clause. The ultimate outcome of this matter cannot be determined at this time.

Energy Conservation Cost Recovery

Every five years, the Florida PSC establishes new numeric conservation goals covering a 10-year period for utilities to reduce annual energy and seasonal peak demand using demand-side management (DSM) programs. After the goals are established, utilities develop plans and programs to meet the approved goals. The costs for these programs are recovered through rates established annually in the energy conservation cost recovery (ECCR) clause.

The most recent goal setting process established new DSM goals for the period 2010 through 2019. The new goals are significantly higher than the goals established in the previous five-year cycle due to a change in the cost-effectiveness test on which the Florida PSC relies to set the goals. The DSM program standards were approved in April 2011, which allow the Company to implement its DSM programs designed to meet the new goals. Several of these new programs were implemented in June 2011 and the costs related to these programs are reflected in the 2012 ECCR factor approved by the Florida PSC. Higher cost recovery rates and achievement of the new DSM goals may result in reduced sales of electricity which could negatively impact results of operations, cash flows, and financial condition if base rates cannot be adjusted on a timely basis.

See BUSINESS under "Rate Matters – Integrated Resource Planning – Gulf Power" in Item 1 for a discussion of the Company's 10-year site plan filed on an annual basis with the Florida PSC.

At December 31, 2012 and 2011, the under recovered energy conservation balance was approximately $0.8 million and $3.1 million, respectively, which is included in under recovered regulatory clause revenues in the balance sheets.

Income Tax Matters

Bonus Depreciation

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 to be placed in service in 2013), which will have a positive impact on the future cash flows of the Company through 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 to be 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 will have a positive impact on the future cash flows of the Company through 2014.

Consequently, the Company's positive cash flow benefit is estimated to be between $30 million and $35 million in 2013.

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Other Matters

The Company is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of business. 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 byproducts, 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.

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 Florida PSC. The Florida PSC sets the rates the Company is permitted to charge customers based on allowable costs. The Company is also subject to cost based regulation by the FERC with respect to wholesale transmission rates. As a result, the Company applies accounting standards which require the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of the accounting standards has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the Company; therefore, the accounting estimates inherent in specific costs such as depreciation 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, income tax, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. The Company periodically evaluates its exposure to such risks and, in accordance with GAAP, records reserves for those matters where a non-tax-related loss is considered probable and reasonably estimable and records a tax asset or liability if it is more likely than not that a tax position will be sustained. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect the Company's financial statements.

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Unbilled Revenues
In November 2012, the Company began using automated meter readings to measure unbilled KWH sales for energy delivered through month-end. As of December 31, 2012, measured unbilled KWH sales represented approximately 90% of total unbilled KWH sales. Increased usage of actual data to compute unbilled revenues reduces the impact that estimates could have on the Company's results of operations; therefore, the Company no longer considers unbilled revenue a critical accounting estimate.
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 $1.3 million or less change in total annual benefit expense and an $18 million or less change in projected obligations.
FINANCIAL CONDITION AND LIQUIDITY
Overview
The Company's financial condition remained stable at December 31, 2012. 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 2013 through 2015, 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 are primarily 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 increased in value as of December 31, 2012 as compared to December 31, 2011. In December 2012, the Company contributed $13.4 million to the qualified pension plan.
Net cash provided from operating activities totaled $419.2 million in 2012, an increase of $43.0 million from 2011, primarily due to an increase in deferred income taxes primarily related to bonus depreciation, partially offset by

decreases in the cash provided from prepaid income taxes, fossil fuel stock, and the recovery of fuel costs. Net cash provided from operating activities totaled $376.2 million in 2011, an increase of $108.4 million from 2010, primarily due to increases in the recovery of fuel costs and prepaid income taxes, primarily due to bonus depreciation.

Net cash used for investing activities totaled $348.6 million, $343.5 million, and $308.4 million for 2012, 2011, and 2010, respectively. The changes in cash used for investing activities were primarily due to gross property additions to utility plant of $325.2 million, $337.8 million, and $285.4 million for 2012, 2011, and 2010, respectively. Funds for the Company's property additions were provided by operating activities, capital contributions, and other financing activities.

Net cash used for financing activities totaled $55.8 million and $31.8 million in 2012 and 2011, respectively. Net cash provided from financing activities was $48.4 million in 2010. The 2012 and 2011 decreases in cash from financing activities were primarily due to short-term debt payments, long-term debt redemptions, and payment of common stock dividends, partially offset by common stock and long-term debt issuances. 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 2012 include an increase of $219.5 million in property, plant, and equipment, primarily due to the addition of environmental control projects at generation facilities, an increase of $190.0 million in accumulated deferred income taxes, primarily related to bonus depreciation, an increase in common stock, without par value due to the issuance of common stock to Southern Company for $40 million and an increase in other regulatory assets, deferred and other deferred credits and liabilities of $49.2 million and $44.2 million, respectively, primarily due to increases in PPAs' deferred capacity expense.

The Company's ratio of common equity to total capitalization, including short-term debt, was 44.5% in 2012 and 43.7% in 2011. See Note 6 to the financial statements for additional information.

Sources of Capital

The Company plans to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily from operating cash flows, 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 on regulatory approval, prevailing market conditions, and other factors.

Security issuances are subject to annual regulatory approval by the Florida PSC pursuant to its rules and regulations. Additionally, with respect to the public offering of securities, the Company files registration statements with the Securities and Exchange Commission (SEC) under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the Florida PSC, as well as the amounts, if any, registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

The Company obtains financing separately without credit support from any affiliate. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of the Company are not commingled with funds of any other company in the Southern Company system.

The Company's current liabilities 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.

At December 31, 2012, the Company had approximately $32.2 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2012 were as follows:

Expires[(a)]				Executable Term-Loans		Due Within One Year	
2013	2014	Total	Unused	One Year	Two Years	Term Out	No Term Out
$80	$195	$275	$275	$45	$—	$45	$35

(a) No credit arrangements expire after 2014.

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 that are restricted only to the indebtedness of the Company. The Company is currently in compliance with all such covenants. The Company expects to renew its credit arrangements, as needed, prior to expiration. These credit arrangements provide liquidity support to the Company's variable rate pollution control revenue bonds and commercial paper borrowings. As of December 31, 2012, the Company had $69 million of outstanding pollution control revenue bonds requiring liquidity support. In addition, the Company has substantial cash flow from operating activities and access to the capital markets to meet liquidity needs.

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 [a]		Short-term Debt During the Period [b]		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		(in millions)		(in millions)
December 31, 2012:					
Commercial paper	$124	0.3 %	$69	0.3 %	$124
December 31, 2011:					
Commercial paper	$111	0.2 %	$53	0.2 %	$111
Short-term bank debt	—	N/A	4	1.3 %	30
Total	$111	0.2 %	$57	0.3 %	
December 31, 2010:					
Commercial paper	$92	0.3 %	$44	0.3 %	$108

(a) Excludes notes payable related to other energy service contracts of $3.2 million, $3.6 million, and $1.2 million at December 31, 2012, 2011, and 2010, respectively.

(b) Average and maximum amounts are based upon daily balances during the twelve-month periods ended December 31, 2012, 2011, and 2010.

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 January 2012, the Company issued to Southern Company 400,000 shares of the Company's common stock, without par value, and realized proceeds of $40 million. Subsequent to December 31, 2012, the Company issued to Southern Company 400,000 shares of the Company's common stock, without par value, and realized proceeds of $40 million. The proceeds were used to repay a portion of the Company's short-term debt and for other general corporate purposes, including the Company's continuous construction program.

In May 2012, the Company issued $100 million aggregate principal amount of Series 2012A 3.10% Senior Notes due May 15, 2022. The net proceeds from the sale of the Series 2012A Senior Notes were used by the Company for the redemption in June 2012 of all of approximately $61 million aggregate principal amount of the Company's Series F 5.60% Senior Insured Quarterly Notes due April 1, 2033 and $30 million aggregate principal amount of the Company's Series H 5.25% Senior Notes due July 15, 2033, to repay a portion of its outstanding short-term indebtedness, and for general corporate purposes, including the Company's continuous construction program.

In November 2012, the Mississippi Business Finance Corporation issued $13 million aggregate principal amount of Mississippi Business Finance Corporation Solid Waste Disposal Facilities Revenue Refunding Bonds, Series 2012 (Gulf Power Company Project), due November 1, 2042 for the benefit of the Company. The proceeds were used to redeem the Mississippi Business Finance Corporation Solid Waste Disposal Facilities Revenue Refunding Bonds, Series 2002 (Gulf Power Company Project) due September 1, 2028.

In addition to any financings that may be necessary to meet capital requirements, contractual obligations, and storm-recovery, the Company plans to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

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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 transportation and storage, and energy price risk management. The maximum potential collateral requirements under these contracts at December 31, 2012 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB- and/or Baa3	$117
Below BBB- and/or Baa3	489

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.

Market Price Risk

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

To mitigate future exposure to changes in interest rates, the Company may enter into derivatives which are designated as hedges. The weighted average interest rate on $69.3 million of outstanding variable rate long-term debt that has not been hedged at January 1, 2013 was 0.13%. 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 $693,000 at January 1, 2013. See Note 1 to the financial statements under "Financial Instruments" and Note 10 to the financial statements for additional information.

To mitigate residual risks relative to natural gas purchases, the Company continues to manage a financial hedging program for fuel purchased to operate its electric generating fleet implemented per the guidelines of the Florida PSC. The changes in fair value of energy-related derivative contracts, substantially all of which are composed of regulatory hedges, for the years ended December 31 were as follows:

	2012 Changes	2011 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	$(41)	$(11)
Contracts realized or settled	30	11
Current period changes[(a)]	(12)	(41)
Contracts outstanding at the end of the period, assets (liabilities), net	$(23)	$(41)

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

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The changes in the fair value positions of the energy-related derivative contracts, which are substantially all attributable to both the volume and the price of natural gas, for the years ended December 31 were as follows:

	2012 Changes	2011 Changes
	Fair Value (in millions)	
Natural gas swaps	$17	$(28)
Natural gas options	1	(2)
Other energy-related derivatives	—	—
Total changes	$18	$(30)

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

	2012	2011
	mmBtu* Volume (in millions)	
Commodity – Natural gas swaps	71	35
Commodity – Natural gas options	—	3
Total hedge volume	71	38

*million British thermal units (mmBtu)

The weighted average swap contract cost above market prices was approximately $0.32 per mmBtu as of December 31, 2012 and $1.14 per mmBtu as of December 31, 2011. The change in option fair value is primarily attributable to the volatility of the market and the underlying change in the natural gas price. Natural gas settlements are recovered through the Company's fuel cost recovery clause.

At December 31, 2012 and 2011, 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 fuel cost recovery clause. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred and were not material for any year presented.

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 9 to the financial statements for further discussion of fair value measurements. The maturities of the energy-related derivative contracts, which are all Level 2 of the fair value hierarchy, at December 31, 2012 were as follows:

	Fair Value Measurements December 31, 2012		
	Total Fair Value	Maturity Year 1	Years 2&3
	(in millions)		
Level 1	$—	$—	$—
Level 2	(23)	(15)	(8)
Level 3	—	—	—
Fair value of contracts outstanding at end of period	$(23)	$(15)	$(8)

The Company is exposed to market price risk in the event of nonperformance by counterparties to the energy-related derivative contracts. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's 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

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does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Note 1 to the financial statements under "Financial Instruments" and Note 10 to the financial statements.

Capital Requirements and Contractual Obligations

The construction program of the Company consists of a base level capital investment and capital expenditures to comply with existing environmental statutes and regulations. These amounts include capital expenditures covered under long-term service agreements as well as capital expenditures and compliance costs associated with the MATS rule. Proposed water and coal combustion byproducts rules are not included in the construction program base level capital investment.

The Company's base level construction program investments for existing environmental statutes and regulations and the estimated incremental compliance costs related to the proposed water and coal combustion byproducts rules over the 2013 through 2015 three-year period, based on the assumption that coal combustion byproducts will continue to be regulated as non-hazardous solid waste under the proposed rule, are estimated as follows:

	2013	2014	2015
Construction program:		(in millions)	
Base capital	$177	$141	$138
Existing environmental statutes and regulations, including the MATS rule	158	319	167
Total construction program base level capital investment	$335	$460	$305
Potential incremental environmental compliance investment:			
Proposed water and coal combustion byproducts rules	$—	$18	$70

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; storm impacts; 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; Florida PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

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

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, 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 10 to the financial statements for additional information.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Gulf Power Company 2012 Annual Report

Contractual Obligations

	2013	2014-2015	2016-2017	After 2017	Uncertain Timing[d]	Total
	(in thousands)					
Long-term debt[a] –						
Principal	$60,000	$75,000	$195,000	$923,955	$—	$1,253,955
Interest	55,095	101,295	91,790	628,206	—	876,386
Financial derivative obligations[b]	16,529	10,209	374	—	—	27,112
Preference stock dividends[c]	6,203	12,405	12,405	—	—	31,013
Operating leases	18,930	18,702	2,128	—	—	39,760
Unrecognized tax benefits[d]	—	—	—	—	5,007	5,007
Purchase commitments –						
Capital[e]	313,952	764,631	—	—	—	1,078,583
Fuel[f]	347,607	459,534	216,967	160,095	—	1,184,203
Purchased power[g]	49,015	160,304	184,613	500,398	—	894,330
Other[h]	15,862	32,923	19,194	15,846	—	83,825
Pension and other postretirement benefit plans[i]	3,928	8,559	—	—	—	12,487
Total	$887,121	$1,643,562	$722,471	$2,228,500	$5,007	$5,486,661

(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, 2013, 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) For additional information, see Notes 1 and 10 to the financial statements.

(c) Preference stock does not mature; therefore, amounts are provided for the next five years only.

(d) The timing related to the realization of $5.0 million in unrecognized tax benefits in individual years beyond 12 months cannot be reasonably and reliably estimated due to uncertainties in the timing of the effective settlement of tax positions. See Note 5 to the financial statements under "Unrecognized Tax Benefits" for additional information.

(e) The Company provides estimated capital expenditures for a three-year period, including capital expenditures and compliance costs associated with existing environmental regulations, including the MATS rule. Such amounts exclude the Company's estimates of potential incremental environmental compliance investment to comply with proposed water and coal combustion byproducts rules, which are approximately $18 million and $70 million for years 2014 and 2015, respectively. These amounts also exclude capital expenditures covered under long-term service agreements, which are reflected separately. At December 31, 2012, 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 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, 2012.

(g) The capacity and transmission related costs associated with PPAs are recovered through the purchased power capacity clause. See Notes 3 and 7 to the financial statements 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)

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

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Gulf Power Company 2012 Annual Report

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2012 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 and postretirement benefit plan contributions, financing activities, start and completion of construction projects, filings with state and federal regulatory authorities, impact of the Tax Relief Act, 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 byproducts, and emissions of sulfur, nitrogen, carbon, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, financial reform legislation, 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, 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;
- investment performance of the Company's employee benefit plans;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms;
- 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, 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

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Gulf Power Company 2012 Annual Report

- 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.

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STATEMENTS OF INCOME
For the Years Ended December 31, 2012, 2011, and 2010
Gulf Power Company 2012 Annual Report

	2012	2011	2010
	(in thousands)		
Operating Revenues:			
Retail revenues	$1,144,471	$1,208,490	$1,308,726
Wholesale revenues, non-affiliates	106,881	133,555	109,172
Wholesale revenues, affiliates	123,636	111,346	110,051
Other revenues	64,774	66,421	62,260
Total operating revenues	1,439,762	1,519,812	1,590,209
Operating Expenses:			
Fuel	544,936	662,283	742,322
Purchased power, non-affiliates	51,421	48,882	41,278
Purchased power, affiliates	22,665	41,612	55,948
Other operations and maintenance	314,195	311,358	280,585
Depreciation and amortization	141,038	129,651	121,498
Taxes other than income taxes	97,313	101,302	101,778
Total operating expenses	1,171,568	1,295,088	1,343,409
Operating Income	268,194	224,724	246,800
Other Income and (Expense):			
Allowance for equity funds used during construction	5,221	9,914	7,213
Interest income	1,408	54	123
Interest expense, net of amounts capitalized	(60,250)	(58,150)	(51,897)
Other income (expense), net	(3,227)	(4,066)	(3,011)
Total other income and (expense)	(56,848)	(52,248)	(47,572)
Earnings Before Income Taxes	211,346	172,476	199,228
Income taxes	79,211	61,268	71,514
Net Income	132,135	111,208	127,714
Dividends on Preference Stock	6,203	6,203	6,203
Net Income After Dividends on Preference Stock	$125,932	$105,005	$121,511

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

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STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2012, 2011, and 2010
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	2012	2011	2010
	(in thousands)		
Net Income	$132,135	$111,208	$127,714
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $-, $-, and $(542), respectively	—	—	(863)
Reclassification adjustment for amounts included in net income, net of tax of $360, $360, and $376, respectively	573	573	598
Total other comprehensive income (loss)	573	573	(265)
Comprehensive Income	$132,708	$111,781	$127,449

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

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2012, 2011, and 2010
Gulf Power Company 2012 Annual Report

	2012	2011	2010
	(in thousands)		
Operating Activities:			
Net income	$132,135	$111,208	$127,714
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization, total	147,723	135,790	127,897
Deferred income taxes	174,305	63,228	82,681
Allowance for equity funds used during construction	(5,221)	(9,914)	(7,213)
Pension, postretirement, and other employee benefits	(8,109)	(356)	(23,964)
Stock based compensation expense	1,647	1,318	1,101
Hedge settlements	—	—	1,530
Other, net	4,518	(8,258)	(4,126)
Changes in certain current assets and liabilities —			
-Receivables	8,713	21,518	(36,687)
-Prepayments	417	10,150	(10,796)
-Fossil fuel stock	(6,144)	17,519	15,766
-Materials and supplies	(3,035)	(5,073)	(6,251)
-Prepaid income taxes	355	26,901	(29,630)
-Other current assets	—	40	55
-Accounts payable	(5,195)	(2,528)	15,683
-Accrued taxes	(4,705)	1,475	1,427
-Accrued compensation	481	25	5,122
-Over recovered regulatory clause revenues	(10,858)	10,247	3,192
-Other current liabilities	(7,837)	2,937	4,279
Net cash provided from operating activities	419,190	376,227	267,780
Investing Activities:			
Property additions	(313,257)	(324,372)	(285,793)
Distribution of restricted cash from pollution control revenue bonds	—	—	6,347
Cost of removal net of salvage	(28,993)	(14,471)	(1,145)
Construction payables	1,161	2,902	(21,581)
Payments pursuant to long-term service agreements	(8,119)	(8,007)	(6,011)
Other investing activities	656	420	(262)
Net cash used for investing activities	(348,552)	(343,528)	(308,445)
Financing Activities:			
Increase (decrease) in notes payable, net	16,075	21,324	4,451
Proceeds —			
Common stock issued to parent	40,000	50,000	50,000
Capital contributions from parent company	2,106	2,101	2,242
Pollution control revenue bonds	13,000	—	21,000
Senior notes	100,000	125,000	300,000
Redemptions —			
Pollution control revenue bonds	(13,000)	—	—
Senior notes	(91,363)	(608)	(215,515)

Other long-term debt	—	(110,000)	—
Payment of preference stock dividends	(6,203)	(6,203)	(6,203)
Payment of common stock dividends	(115,800)	(110,000)	(104,300)
Other financing activities	(614)	(3,419)	(3,253)
Net cash provided from (used for) financing activities	(55,799)	(31,805)	48,422
Net Change in Cash and Cash Equivalents	14,839	894	7,757
Cash and Cash Equivalents at Beginning of Year	17,328	16,434	8,677
Cash and Cash Equivalents at End of Year	$32,167	$17,328	$16,434
Supplemental Cash Flow Information:			
Cash paid during the period for —			
Interest (net of $2,500, $3,951 and $2,875 capitalized, respectively)	$58,255	$55,486	$42,521
Income taxes (net of refunds)	(96,639)	(26,345)	17,224
Noncash transactions — accrued property additions at year-end	27,369	19,439	14,475

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

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BALANCE SHEETS
At December 31, 2012 and 2011
Gulf Power Company 2012 Annual Report

Assets	2012	2011
	(in thousands)	
Current Assets:		
Cash and cash equivalents	$32,167	$17,328
Receivables —		
Customer accounts receivable	58,449	72,754
Unbilled revenues	53,363	49,921
Under recovered regulatory clause revenues	6,138	5,530
Other accounts and notes receivable	11,859	13,350
Affiliated companies	13,624	14,844
Accumulated provision for uncollectible accounts	(1,490)	(1,962)
Fossil fuel stock, at average cost	153,710	147,567
Materials and supplies, at average cost	53,365	49,781
Other regulatory assets, current	30,576	35,849
Prepaid expenses	62,877	28,327
Other current assets	2,690	2,051
Total current assets	477,328	435,340
Property, Plant, and Equipment:		
In service	4,260,844	3,846,446
Less accumulated provision for depreciation	1,168,055	1,124,291
Plant in service, net of depreciation	3,092,789	2,722,155
Construction work in progress	136,062	287,173
Total property, plant, and equipment	3,228,851	3,009,328
Other Property and Investments	15,737	16,394
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	50,139	48,210
Other regulatory assets, deferred	372,294	323,116
Other deferred charges and assets	33,053	39,493
Total deferred charges and other assets	455,486	410,819
Total Assets	$4,177,402	$3,871,881

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

BALANCE SHEETS
At December 31, 2012 and 2011
Gulf Power Company 2012 Annual Report

Liabilities and Stockholder's Equity	2012	2011
	(in thousands)	
Current Liabilities:		
Securities due within one year	$60,000	$—
Notes payable	127,002	114,507
Accounts payable —		
Affiliated	66,161	54,874
Other	54,551	63,265
Customer deposits	34,749	35,779
Accrued taxes —		
Accrued income taxes	45	1,362
Other accrued taxes	7,036	12,114
Accrued interest	12,364	14,018
Accrued compensation	14,966	14,485
Other regulatory liabilities, current	25,887	35,639
Liabilities from risk management activities	16,529	22,786
Other current liabilities	19,930	22,916
Total current liabilities	439,220	391,745
Long-Term Debt (See accompanying statements)	1,185,870	1,235,447
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	648,952	458,978
Accumulated deferred investment tax credits	5,408	6,760
Employee benefit obligations	126,871	109,740
Other cost of removal obligations	213,413	214,598
Other regulatory liabilities, deferred	47,863	44,843
Other deferred credits and liabilities	231,065	186,824
Total deferred credits and other liabilities	1,273,572	1,021,743
Total Liabilities	2,898,662	2,648,935
Preference Stock (See accompanying statements)	97,998	97,998
Common Stockholder's Equity (See accompanying statements)	1,180,742	1,124,948
Total Liabilities and Stockholder's Equity	$4,177,402	$3,871,881
Commitments and Contingent Matters (See notes)		

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

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STATEMENTS OF CAPITALIZATION
At December 31, 2012 and 2011
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	2012	2011	2012	2011
	(in thousands)		(percent of total)	
Long Term Debt:				
Long-term notes payable —				
4.35% due 2013	$60,000	$60,000		
4.90% due 2014	75,000	75,000		
5.30% due 2016	110,000	110,000		
5.90% due 2017	85,000	85,000		
3.10% to 5.75% due 2020-2051	615,000	606,363		
Total long-term notes payable	945,000	936,363		
Other long-term debt —				
Pollution control revenue bonds —				
0.55% to 6.00% due 2022-2049	239,625	239,625		
Variable rates (0.13% to 0.17% at 1/1/13) due 2022-2039	69,330	69,330		
Total other long-term debt	308,955	308,955		
Unamortized debt discount	(8,085)	(9,871)		
Total long-term debt (annual interest requirement — $55.1 million)	1,245,870	1,235,447		
Less amount due within one year	60,000	—		
Long-term debt excluding amount due within one year	1,185,870	1,235,447	48.1%	50.2%
Preferred and Preference Stock:				
Authorized - 20,000,000 shares—preferred stock				
- 10,000,000 shares—preference stock				
Outstanding - $100 par or stated value — 6% preference stock	53,886	53,886		
— 6.45% preference stock	44,112	44,112		
- 1,000,000 shares (non-cumulative)				
Total preference stock (annual dividend requirement — $6.2 million)	97,998	97,998	4.0	4.0
Common Stockholder's Equity:				
Common stock, without par value —				
Authorized - 20,000,000 shares				
Outstanding - 2012: 4,542,717 shares				
- 2011: 4,142,717 shares	393,060	353,060		
Paid-in capital	547,798	542,709		
Retained earnings	241,465	231,333		
Accumulated other comprehensive income (loss)	(1,581)	(2,154)		
Total common stockholder's equity	1,180,742	1,124,948	47.9	45.8
Total Capitalization	$2,464,610	$2,458,393	100.0%	100.0%

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

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STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
For the Years Ended December 31, 2012, 2011, and 2010
Gulf Power Company 2012 Annual Report

	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
	(in thousands)					
Balance at December 31, 2009	3,143	$253,060	$534,577	$219,117	$(2,462)	$1,004,292
Net income after dividends on preference stock	—	—	—	121,511	—	121,511
Issuance of common stock	500	50,000	—	—	—	50,000
Capital contributions from parent company	—	—	3,798	—	—	3,798
Other comprehensive income (loss)	—	—	—	—	(265)	(265)
Cash dividends on common stock	—	—	—	(104,300)	—	(104,300)
Balance at December 31, 2010	3,643	303,060	538,375	236,328	(2,727)	1,075,036
Net income after dividends on preference stock	—	—	—	105,005	—	105,005
Issuance of common stock	500	50,000	—	—	—	50,000
Capital contributions from parent company	—	—	4,334	—	—	4,334
Other comprehensive income (loss)	—	—	—	—	573	573
Cash dividends on common stock	—	—	—	(110,000)	—	(110,000)
Balance at December 31, 2011	4,143	353,060	542,709	231,333	(2,154)	1,124,948
Net income after dividends on preference stock	—	—	—	125,932	—	125,932
Issuance of common stock	400	40,000	—	—	—	40,000
Capital contributions from parent company	—	—	5,089	—	—	5,089
Other comprehensive income (loss)	—	—	—	—	573	573
Cash dividends on common stock	—	—	—	(115,800)	—	(115,800)
Balance at December 31, 2012	4,543	$393,060	$547,798	$241,465	$(1,581)	$1,180,742

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

NOTES TO FINANCIAL STATEMENTS
Gulf Power Company 2012 Annual Report
1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES
General
Gulf 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, 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), Georgia Power Company (Georgia 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 customers in northwest Florida 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.
The equity method is used for entities in which the Company has significant influence but does not control.
The Company is subject to regulation by the Federal Energy Regulatory Commission (FERC) and the Florida 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 and power pool transactions. Costs for these services amounted to $95.9 million, $97.4 million, and $98.8 million during 2012, 2011, and 2010, 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 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 agreements with Georgia Power and Mississippi Power under which the Company owns a portion of Plant Scherer and Plant Daniel, respectively. Georgia Power operates Plant Scherer and Mississippi Power operates Plant Daniel. The Company reimbursed Georgia Power $6.9 million, $6.7 million, and $8.9 million and Mississippi Power $21.1 million, $23.4 million, and $25.0 million in 2012, 2011, and 2010, respectively, for its proportionate share of related expenses. See Note 4 and Note 7 under "Operating Leases" for additional information.
The Company entered into a power purchase agreement (PPA) with Southern Power for a total of approximately 292 megawatts (MWs) annually from June 2009 through May 2014. Purchased power expenses associated with the PPA were $14.7 million, $14.3 million, and $14.5 million in 2012, 2011, and 2010, respectively, and fuel costs associated with the PPA were $2.6 million, $1.8 million, and $3.3 million in 2012, 2011, and 2010, respectively. These costs have been approved for recovery by the Florida PSC through the Company's fuel and purchased power capacity cost

recovery clauses. Additionally, the Company had $4.2 million of deferred capacity expenses included in prepaid expenses and other regulatory liabilities, current in the balance sheets at December 31, 2012 and 2011, respectively. See Note 7 under "Fuel and Purchased Power Agreements" for additional information.
The Company has an agreement with Georgia Power under the transmission facility cost allocation tariff for delivery of power from the Company's resources in the state of Georgia. The Company reimbursed Georgia Power $2.4 million in each of the years 2012, 2011, and 2010 for its share of related expenses.

NOTES (continued)
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The Company has an agreement with Alabama Power under which Alabama Power will make transmission system upgrades to ensure firm delivery of energy under a non-affiliate PPA, which was entered into in 2009 for the capacity and energy from a combined cycle plant located in Autauga County, Alabama. Revenue requirement obligations to Alabama Power for these upgrades are estimated to be $136.7 million for the entire project. These costs began in July 2012 and will continue through 2023. The Company reimbursed Alabama Power $3.0 million in 2012 for the revenue requirements. These costs have been approved for recovery by the Florida PSC through the Company's purchased power capacity cost recovery clause and by the FERC in the transmission facilities cost allocation tariff.

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 2012 or 2010. In 2011, the Company provided storm restoration assistance to Alabama Power totaling $1.4 million.

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.

New Accounting Pronouncements

In June 2011, the Financial Accounting Standards Board (FASB) issued guidance, ASU 2011-05, Presentation of Comprehensive Income, requiring companies to present the total of comprehensive income, the components of net income, and the components of other comprehensive income, in a single continuous statement of comprehensive income or in two separate but consecutive statements. In October 2012, the FASB issued additional guidance, ASU 2012-04, Technical Corrections and Improvements (ASU 2012-04), in which it clarified that those companies presenting consecutive statements must begin the statement of comprehensive income with net income. The Company retroactively adopted the guidance in ASU 2012-04 beginning with its financial statements for the three years ended December 31, 2012, 2011, and 2010.

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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.

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

	2012	2011	Note
	(in thousands)		
Deferred income tax charges	$46,788	$44,533	(a)
Deferred income tax charges — Medicare subsidy	3,678	4,005	(b)
Asset retirement obligations	(5,793)	(5,653)	(a,j)
Other cost of removal obligations	(213,413)	(214,598)	(a)
Deferred income tax credits	(6,515)	(8,113)	(a)
Loss on reacquired debt	16,400	14,437	(c)
Vacation pay	9,238	8,973	(d,j)
Under recovered regulatory clause revenues	3,523	3,133	(e)
Over recovered regulatory clause revenues	(17,092)	(27,950)	(e)
Property damage reserve	(31,956)	(30,473)	(f)
Fuel hedging (realized and unrealized) losses	29,038	43,071	(g,j)
Fuel hedging (realized and unrealized) gains	(4,358)	(197)	(g,j)
PPA charges	137,568	94,986	(j,k)
Generation site selection/evaluation costs	1,344	20,415	(l)
Other regulatory assets	9,690	1,675	(e,j)
Environmental remediation	60,452	61,625	(h,j)
PPA credits	(7,502)	(7,536)	(j,k)
Other regulatory liabilities	(534)	(798)	(f)
Retiree benefit plans, net	141,429	116,091	(i,j)
Total regulatory assets (liabilities), net	$171,985	$117,626	

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 65 years. Asset retirement and removal assets and liabilities will be settled and trued up following completion of the related activities.

(b) Recovered and amortized over periods not exceeding 14 years.

(c) Recovered over either the remaining life of the original issue or, if refinanced, over the life of the new issue, which may range up to 40 years.

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

(e) Recorded and recovered or amortized as approved by the Florida PSC, generally within one year.

(f) Recorded and recovered or amortized as approved by the Florida PSC.

(g) Fuel hedging assets and liabilities are recognized over the life of the underlying hedged purchase contracts, which generally do not exceed five years. Upon final settlement, costs are recovered through the fuel cost recovery clause.

(h) Recovered through the environmental cost recovery clause when the remediation is performed.

(i) Recovered and amortized over the average remaining service period which may range up to 14 years. See Note 2 for additional information.

(j) Not earning a return as offset in rate base by a corresponding asset or liability.
(k) Recovered over the life of the PPA for periods up to 14 years.
(l) Deferred pursuant to Florida Statute while the Company continues to evaluate certain potential new generation projects.

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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. The Company continuously monitors the over or under recovered fuel cost balance in light of the inherent variability in fuel costs. The Company is required to notify the Florida PSC if the projected fuel cost over or under recovery is expected to exceed 10% of the projected fuel revenue applicable for the period and indicate if an adjustment to the fuel cost recovery factor is being requested. The Company has similar retail cost recovery clauses for energy conservation costs, purchased power capacity costs, and environmental compliance costs. Revenues are adjusted for differences between these actual costs and amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors. Annually, the Company petitions for recovery of projected costs including any true-up amounts from prior periods, and approved rates are implemented each January. See Note 3 under "Retail Regulatory Matters" for additional information.

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

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense generally includes fuel transportation costs and the cost of purchased emissions allowances as they are used. Fuel expense and emissions allowance costs are recovered by the Company through the fuel cost recovery and environmental cost recovery rates, respectively, approved annually by the Florida PSC.

Income and Other Taxes

The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. Investment tax credits 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:

	2012	2011
	(in thousands)	
Generation	$2,598,773	$2,283,494

Transmission	429,341	368,542
Distribution	1,069,065	1,030,546
General	161,379	161,322
Plant acquisition adjustment	2,286	2,542
Total plant in service	$4,260,844	$3,846,446

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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 expense as incurred or performed.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.6% in 2012, 3.5% in 2011, and 3.5% in 2010. Depreciation studies are conducted periodically to update the composite rates. These studies are approved by the Florida PSC and the FERC. When property subject to depreciation is retired or otherwise disposed of 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.

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 an order from the Florida PSC allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations are reflected in the balance sheets as a regulatory liability.

The liability for asset retirement obligations primarily relates to the Company's combustion turbines at its Pea Ridge facility, various landfill sites, a barge unloading dock, asbestos removal, ash ponds, and disposal of polychlorinated biphenyls in certain transformers. The Company also has identified retirement obligations related to certain transmission and distribution facilities, certain wireless communication towers, and certain structures authorized by the U.S. Army Corps of Engineers. However, liabilities for the removal of these assets have not been recorded because the range of time over which the Company may settle these obligations is unknown and cannot be reasonably estimated. The Company will continue to recognize in the statements of income allowed removal costs in accordance with its regulatory treatment. Any differences between costs recognized in accordance with accounting standards related to asset retirement and environmental obligations and those reflected in rates are recognized as either a regulatory asset or liability, as ordered by the Florida PSC, and are reflected in the balance sheets.

Details of the asset retirement obligations included in the balance sheets are as follows:

	2012	2011
	(in thousands)	
Balance at beginning of year	$10,729	$11,470
Liabilities incurred	—	106
Liabilities settled	(107)	(1,050)
Accretion	507	545
Cash flow revisions	4,926	(342)
Balance at end of year	$16,055	$10,729

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 over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in calculating taxable income. The average annual AFUDC rate was 6.72% for the year 2012. The average annual AFUDC rate was 7.65% for both 2011 and 2010. AFUDC, net of income taxes, as a percentage of net income after dividends on preference stock was 5.36%, 11.75%, and 7.39% for

2012, 2011, and 2010, respectively.

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

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than the fair value. For assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell in order to determine if an impairment loss is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change.

Property Damage Reserve

The Company accrues for the cost of repairing damages from major storms and other uninsured property damages, including uninsured damages to transmission and distribution facilities, generation facilities, and other property. The costs of such damage are charged to the reserve. The Florida PSC approved annual accrual to the property damage reserve is $3.5 million, with a target level for the reserve between $48.0 million and $55.0 million. The Florida PSC also authorized the Company to make additional accruals above the $3.5 million at the Company's discretion. The Company accrued total expenses of $3.5 million in each of 2012, 2011, and 2010. As of December 31, 2012 and 2011, the balance in the Company's property damage reserve totaled approximately $32.0 million and $30.5 million, respectively, which is included in deferred liabilities in the balance sheets.

When the property damage reserve is inadequate to cover the cost of major storms, the Florida PSC can authorize a storm cost recovery surcharge to be applied to customer bills. Such a surcharge was authorized in 2005 after Hurricane Ivan in 2004 and was extended by a 2006 Florida PSC order approving a stipulation to address costs incurred as a result of Hurricanes Dennis and Katrina in 2005. Under the 2006 Florida PSC order, if the Company incurs cumulative costs for storm recovery activities in excess of $10 million during any calendar year, the Company would be permitted to file a streamlined formal request for an interim surcharge. Any interim surcharge would provide for the recovery, subject to refund, of up to 80% of the claimed costs for storm recovery activities. The Company would then petition the Florida PSC for full recovery through a final or non-interim surcharge or other cost recovery mechanism. After the effective date of new base rates, the Company will retain the right to request relief on an expedited basis from the Florida PSC without the thresholds set forth in the stipulation.

Injuries and Damages Reserve

The Company is subject to claims and lawsuits arising in the ordinary course of business. As permitted by the Florida PSC, the Company accrues for the uninsured costs of injuries and damages by charges to income amounting to $1.6 million annually. The Florida PSC has also given the Company the flexibility to increase its annual accrual above $1.6 million to the extent the balance in the reserve does not exceed $2 million and to defer expense recognition of liabilities greater than the balance in the reserve. The cost of settling claims is charged to the reserve. The injuries and damages reserve was $3.1 million and $2.7 million at December 31, 2012 and 2011, respectively. For 2012, $1.6 million and $1.5 million are included in current liabilities and deferred credits and other liabilities in the balance sheets, respectively. For 2011, $1.6 million and $1.1 million are included in current liabilities and deferred credits and other liabilities in the balance sheets, respectively. There were no liabilities in excess of the reserve balance at December 31, 2012 and 2011.

Cash and Cash Equivalents

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

Materials and Supplies

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

Fuel Inventory

Fuel inventory includes the average cost of oil, natural gas, coal, transportation, and emissions allowances. Fuel is charged to inventory when purchased and then expensed, at weighted average cost, as used. Fuel expense and emissions allowance costs are recovered by the Company through the fuel cost recovery and environmental cost recovery rates, respectively, approved annually by the Florida PSC. Emissions allowances granted by the

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 9 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 Florida 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 10 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, 2012.

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.

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). In December 2012, the Company contributed $13.4 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2013. The Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The Company funds its other postretirement trusts to the extent required by the FERC. For the year ending December 31, 2013, no other postretirement trust contributions are expected.

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 2009 for the 2010 plan year using discount rates for the pension plans and the other postretirement benefit plans of 5.93% and 5.84%, respectively, and an annual salary increase of 4.18%.

	2012		2011		2010	
Discount rate:						
Pension plans	4.27	%	4.98	%	5.53	%
Other postretirement benefit plans	4.06		4.88		5.41	
Annual salary increase	3.59		3.84		3.84	
Long-term return on plan assets:						
Pension plans	8.20		8.45		8.45	
Other postretirement benefit plans	8.02		8.11		8.18	

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.

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An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) is the weighted average medical care cost trend rate. The weighted average medical care cost trend rates used in measuring the APBO as of December 31, 2012 were as follows:

	Initial Cost Trend Rate	Ultimate Cost Trend Rate	Year That Ultimate Rate Is Reached
Pre-65	8.00%	5.00%	2020
Post-65 medical	6.00	5.00	2020
Post-65 prescription	6.00	5.00	2020

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, 2012 as follows:

	1 Percent Increase	1 Percent Decrease
	(in thousands)	
Benefit obligation	$3,399	$(2,897)
Service and interest costs	198	(169)

Pension Plans

The total accumulated benefit obligation for the pension plans was $371 million at December 31, 2012 and $321 million at December 31, 2011. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2012 and 2011were as follows:

	2012	2011
	(in thousands)	
Change in benefit obligation		
Benefit obligation at beginning of year	$352,834	$316,286
Service cost	9,101	8,431
Interest cost	17,199	17,074
Benefits paid	(14,046)	(13,807)
Plan amendments	426	—
Actuarial loss	47,987	24,850
Balance at end of year	413,501	352,834
Change in plan assets		
Fair value of plan assets at beginning of year	304,324	307,828
Actual return on plan assets	45,762	9,552
Employer contributions	14,220	751
Benefits paid	(14,046)	(13,807)
Fair value of plan assets at end of year	350,260	304,324
Accrued liability	$(63,241)	$(48,510)

At December 31, 2012, the projected benefit obligations for the qualified and non-qualified pension plans were $393 million and $20 million, respectively. All pension plan assets are related to the qualified pension plan.

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Amounts recognized in the balance sheets at December 31, 2012 and 2011 related to the Company's pension plans consist of the following:

	2012	2011
	(in thousands)	
Other regulatory assets	$139,261	$115,853
Current liabilities, other	(855)	(794)
Employee benefit obligations	(62,386)	(47,716)

Presented below are the amounts included in regulatory assets at December 31, 2012 and 2011 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 2013.

	2012	2011	Estimated Amortization in 2013
	(in thousands)		
Prior service cost	$5,565	$6,402	$1,164
Net (gain) loss	133,696	109,451	8,385
Other regulatory assets	$139,261	$115,853	

The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2012 and 2011 are presented in the following table:

	Regulatory Assets (in thousands)
Balance at December 31, 2010	$75,096
Net (gain) loss	42,531
Change in prior service costs	—
Reclassification adjustments:	
Amortization of prior service costs	(1,262)
Amortization of net gain (loss)	(512)
Total reclassification adjustments	(1,774)
Total change	40,757
Balance at December 31, 2011	$115,853
Net (gain) loss	28,157
Change in prior service costs	426
Reclassification adjustments:	
Amortization of prior service costs	(1,262)
Amortization of net gain (loss)	(3,913)
Total reclassification adjustments	(5,175)
Total change	23,408
Balance at December 31, 2012	$139,261

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Components of net periodic pension cost were as follows:

	2012	2011	2010
	(in thousands)		
Service cost	$9,101	$8,431	$7,853
Interest cost	17,199	17,074	17,305
Expected return on plan assets	(25,932)	(27,232)	(24,695)
Recognized net (gain) loss	3,913	512	398
Net amortization	1,262	1,262	1,302
Net periodic pension cost	$5,543	$47	$2,163

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, 2012, estimated benefit payments were as follows:

	Benefit Payments
	(in thousands)
2013	$15,767
2014	16,606
2015	17,427
2016	18,272
2017	19,383
2018 to 2022	113,108

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Other Postretirement Benefits

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2012 and 2011 were as follows:

	2012	2011
	(in thousands)	
Change in benefit obligation		
Benefit obligation at beginning of year	$70,923	$69,617
Service cost	1,167	1,132
Interest cost	3,367	3,658
Benefits paid	(3,854)	(4,189)
Actuarial loss	3,468	292
Plan amendments	—	—
Retiree drug subsidy	324	413
Balance at end of year	75,395	70,923
Change in plan assets		
Fair value of plan assets at beginning of year	14,978	15,697
Actual return on plan assets	2,131	514
Employer contributions	2,648	2,543
Benefits paid	(3,530)	(3,776)
Fair value of plan assets at end of year	16,227	14,978
Accrued liability	$(59,168)	$(55,945)

Amounts recognized in the balance sheets at December 31, 2012 and 2011 related to the Company's other postretirement benefit plans consist of the following:

	2012	2011
	(in thousands)	
Regulatory assets	$2,169	$239
Current liabilities, other	(661)	(624)
Employee benefit obligations	(58,507)	(55,321)

Presented below are the amounts included in regulatory assets at December 31, 2012 and 2011 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 2013.

	2012	2011	Estimated Amortization in 2013
	(in thousands)		
Prior service cost	$324	$510	$186
Net (gain) loss	1,845	(464)	—
Transition obligation	—	193	—
Regulatory assets (liabilities)	$2,169	$239	

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The changes in the balance of regulatory assets and regulatory liabilities related to the other postretirement benefit plans for the plan years ended December 31, 2012 and 2011 are presented in the following table:

	Regulatory Assets	Regulatory Liabilities
	(in thousands)	
Balance at December 31, 2010	$—	$(166)
Net (gain) loss	635	166
Change in prior service costs/transition obligation	—	—
Reclassification adjustments:		
Amortization of transition obligation	(257)	—
Amortization of prior service costs	(186)	—
Amortization of net gain (loss)	47	—
Total reclassification adjustments	(396)	—
Total change	239	166
Balance at December 31, 2011	$239	$—
Net (gain) loss	2,309	—
Change in prior service costs/transition obligation	—	—
Reclassification adjustments:		
Amortization of transition obligation	(193)	—
Amortization of prior service costs	(186)	—
Amortization of net gain (loss)	—	—
Total reclassification adjustments	(379)	—
Total change	1,930	—
Balance at December 31, 2012	$2,169	$—

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

	2012	2011	2010
	(in thousands)		
Service cost	$1,167	$1,132	$1,304
Interest cost	3,367	3,658	4,121
Expected return on plan assets	(1,311)	(1,445)	(1,481)
Net amortization	379	396	406
Net postretirement cost	$3,602	$3,741	$4,350

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Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the APBO for the other postretirement benefit plans. 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 thousands)		
2013	$4,473	$(488)	$3,985
2014	4,707	(537)	4,170
2015	4,903	(589)	4,314
2016	5,117	(643)	4,474
2017	5,211	(705)	4,506
2018 to 2022	26,913	(3,804)	23,109

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, 2012 and 2011, along with the targeted mix of assets for each plan, is presented below:

	Target	2012	2011
Pension plan assets:			
Domestic equity	26%	28%	29%
International equity	25	24	25
Fixed income	23	27	23
Special situations	3	1	—
Real estate investments	14	13	14
Private equity	9	7	9
Total	100%	100%	100%
Other postretirement benefit plan assets:			
Domestic equity	25%	27%	28%
International equity	24	23	24
Domestic fixed income	25	29	26
Special situations	3	1	—
Real estate investments	14	13	13
Private equity	9	7	9
Total	100%	100%	100%

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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, 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.
- 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, 2012 and 2011. 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:

- Investments in equity securities: 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.
- Investments in fixed income securities: 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.
- Investments in private equity and real estate: 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.

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The fair values of pension plan assets as of December 31, 2012 and 2011 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, 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 thousands)			
Assets:				
Domestic equity*	$51,215	$29,499	$—	$80,714
International equity*	40,166	43,120	—	83,286
Fixed income:				
U.S. Treasury, government, and agency bonds	—	22,724	—	22,724
Mortgage- and asset-backed securities	—	5,594	—	5,594
Corporate bonds	—	38,534	139	38,673
Pooled funds	—	17,581	—	17,581
Cash equivalents and other	208	24,148	—	24,356
Real estate investments	11,362	—	37,039	48,401
Private equity	—	—	26,129	26,129
Total	$102,951	$181,200	$63,307	$347,458

* 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, 2011:	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 thousands)			
Assets:				
Domestic equity*	$51,686	$23,857	$—	$75,543
International equity*	53,130	15,223	—	68,353
Fixed income:				
U.S. Treasury, government, and agency bonds	—	19,375	—	19,375
Mortgage- and asset-backed securities	—	6,047	—	6,047
Corporate bonds	—	37,274	120	37,394
Pooled funds	—	16,998	—	16,998
Cash equivalents and other	30	6,228	—	6,258
Real estate investments	9,838	—	34,989	44,827
Private equity	—	—	26,053	26,053
Total	$114,684	$125,002	$61,162	$300,848

* 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.

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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, 2012 and 2011 were as follows:

	2012 Real Estate Investments	2012 Private Equity	2011 Real Estate Investments	2011 Private Equity
	(in thousands)			
Beginning balance	$34,989	$26,053	$30,355	$28,727
Actual return on investments:				
Related to investments held at year end	1,918	44	3,021	(538)
Related to investments sold during the year	132	1,396	896	1,941
Total return on investments	2,050	1,440	3,917	1,403
Purchases, sales, and settlements	—	(1,364)	717	(4,077)
Transfers into/out of Level 3	—	—	—	—
Ending balance	$37,039	$26,129	$34,989	$26,053

The fair values of other postretirement benefit plan assets as of December 31, 2012 and 2011 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, 2012:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in thousands)			
Assets:				
Domestic equity*	$2,290	$1,319	$—	$3,609
International equity*	1,795	1,928	—	3,723
Fixed income:				
U.S. Treasury, government, and agency bonds	—	1,016	—	1,016
Mortgage- and asset-backed securities	—	250	—	250
Corporate bonds	—	1,722	6	1,728
Pooled funds	—	1,298	—	1,298
Cash equivalents and other	9	1,078	—	1,087
Real estate investments	508	—	1,667	2,175
Private equity	—	15	1,155	1,170
Total	$4,602	$8,626	$2,828	$16,056

* 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.

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As of December 31, 2011:	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 thousands)			
Assets:				
Domestic equity*	$2,445	$1,128	$—	$3,573
International equity*	2,511	719	—	3,230
Fixed income:				
U.S. Treasury, government, and agency bonds	—	918	—	918
Mortgage- and asset-backed securities	—	286	—	286
Corporate bonds	—	1,761	—	1,761
Pooled funds	—	1,328	—	1,328
Cash equivalents and other	1	295	—	296
Real estate investments	466	—	1,657	2,123
Private equity	—	—	1,232	1,232
Total	$5,423	$6,435	$2,889	$14,747

* 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, 2012 and 2011 were as follows:

	2012 Real Estate Investments	2012 Private Equity	2011 Real Estate Investments	2011 Private Equity
	(in thousands)			
Beginning balance	$1,657	$1,232	$1,452	$1,375
Actual return on investments:				
Related to investments held at year end	107	(1)	129	(26)
Related to investments sold during the year	6	80	42	77
Total return on investments	113	79	171	51
Purchases, sales, and settlements	(103)	(156)	34	(194)
Transfers into/out of Level 3	—	—	—	—
Ending balance	$1,667	$1,155	$1,657	$1,232

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 2012, 2011, and 2010 were $4.0 million, $3.7 million, and $3.6 million, respectively.

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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 byproducts, 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
In 1999, the EPA brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including Alabama Power and Georgia Power, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. The EPA alleged NSR violations at five coal-fired generating facilities operated by Alabama Power and three coal-fired generating facilities operated by Georgia Power, including a unit co-owned by the Company. The civil action sought penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. These actions were filed concurrently with the issuance of notices of violation of the NSR provisions to the Company with respect to the Company's Plant Crist. The case against Georgia Power (including claims related to the unit co-owned by the Company) was administratively closed in 2001 and has not been reopened. After Alabama Power was dismissed from the original action, the EPA filed a separate action in 2001 against Alabama Power in the U.S. District Court for the Northern District of Alabama.
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.
Climate Change Litigation
Kivalina Case
In 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs allege that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that some of the defendants (including Southern Company) acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. In 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case. On September 21, 2012, the U.S. Court of Appeals for the Ninth Circuit upheld the U.S. District Court for the Northern District of California's dismissal of the case. On November 27, 2012, the U.S. Court of Appeals for the Ninth Circuit denied the plaintiffs' request for review of the decision. On February 25, 2013, the plaintiffs filed a petition for writ of

certiorari with the U.S. Supreme Court. Southern Company believes that these claims are without merit. While Southern Company believes the likelihood of loss is remote based on existing case law, it is not possible to predict with certainty whether the Company will incur any liability in connection with this matter. The ultimate outcome of this matter cannot be determined at this time.

Hurricane Katrina Case

In 2005, immediately following Hurricane Katrina, a lawsuit was filed in the U.S. District Court for the Southern District of Mississippi by Ned Comer on behalf of Mississippi residents seeking recovery for property damage and personal injuries caused by Hurricane Katrina. In 2006, the plaintiffs amended the complaint to include Southern Company and many other electric utilities, oil

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companies, chemical companies, and coal producers. The plaintiffs allege that the defendants contributed to climate change, which contributed to the intensity of Hurricane Katrina. In 2007, the U.S. District Court for the Southern District of Mississippi dismissed the case. On appeal to the U.S. Court of Appeals for the Fifth Circuit, a three-judge panel reversed the U.S. District Court for the Southern District of Mississippi, holding that the case could proceed, but on rehearing, the full U.S. Court of Appeals for the Fifth Circuit dismissed the plaintiffs' appeal, resulting in reinstatement of the decision of the U.S. District Court for the Southern District of Mississippi in favor of the defendants. In May 2011, the plaintiffs filed an amended version of their class action complaint, arguing that the earlier dismissal was on procedural grounds and under Mississippi law the plaintiffs have a right to re-file. The amended complaint was also filed against numerous chemical, coal, oil, and utility companies, including the Company. On March 20, 2012, the U.S. District Court for the Southern District of Mississippi dismissed the plaintiffs' amended complaint. On April 16, 2012, the plaintiffs appealed the case to the U.S. Court of Appeals for the Fifth Circuit. The Company believes that these claims are without merit. While the Company believes the likelihood of loss is remote based on existing case law, it is not possible to predict with certainty whether the Company will incur any liability in connection with this matter. 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. The Company received authority from the Florida PSC to recover approved environmental compliance costs through the environmental cost recovery clause. The Florida PSC reviews costs and adjusts rates up or down annually.

The Company recognizes a liability for environmental remediation costs only when it determines a loss is probable. At December 31, 2012, the Company's environmental remediation liability included estimated costs of environmental remediation projects of approximately $60.5 million. For 2012, approximately $2.6 million was included in under recovered regulatory clause revenues and other current liabilities, and approximately $57.9 million was included in other regulatory assets, deferred and other deferred credits and liabilities. 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 the Company's 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 the Company'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, the Company does not believe that additional liabilities, if any, at these sites would be material to the Company's financial statements.

Retail Regulatory Matters

The Company's rates and charges for service to retail customers are subject to the regulatory oversight of the Florida PSC. The Company's rates are a combination of base rates and several separate cost recovery clauses for specific categories of costs. These separate cost recovery clauses address such items as fuel and purchased energy costs, purchased power capacity costs, energy conservation and demand side management programs, and the costs of compliance with environmental laws and regulations. Costs not addressed through one of the specific cost recovery clauses are recovered through the Company's base rates.

Retail Base Rate Case

On March 12, 2012, the Florida PSC approved an increase in retail base rates and charges of $64 million effective April 11, 2012. The amount of the increase includes the previously approved $38.5 million interim retail rate increase implemented in September 2011. The Florida PSC's decision on the amount of the increase also included a determination that none of the base rate revenues collected on an interim basis would be refunded. The Company's authorized retail ROE is a range of 9.25% to 11.25% with new retail base rates set at the midpoint retail ROE of 10.25%. In addition, the Florida PSC also approved a step increase to the Company's retail base rates and charges of $4 million effective in January 2013.

Cost Recovery Clauses

On November 5, 2012, the Florida PSC approved the Company's annual rate clause requests for its fuel, purchased power capacity, conservation, and environmental compliance cost recovery factors for 2013. The net effect of the approved changes is a 1.9% rate increase for residential customers using 1,000 KWHs per month.

Revenues for all cost recovery clauses, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor for fuel and purchased power will have no significant effect on the Company's revenues or net income, but will affect annual cash flow. The recovery provisions for environmental compliance and energy conservation include related expenses and a return on net average investment.

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Fuel Cost Recovery
The Company has established fuel cost recovery rates as approved by the Florida PSC. If, at any time during the year, the projected year-end fuel cost over or under recovery balance exceeds 10% of the projected fuel revenue applicable for the period, the Company is required to notify the Florida PSC and indicate if an adjustment to the fuel cost recovery factor is being requested. On February 14, 2012, the Florida PSC approved a reduction to the fuel cost recovery factors starting in March 2012. The effect of the approved change was a 2.7% decrease for residential customers using 1,000 KWHs per month. On June 19, 2012, the Florida PSC approved an additional decrease in the Company's fuel rates lowering the 1,000 KWH residential bill 7.8% to reduce annual billings by approximately $58.8 million effective July 2, 2012.
The increase in the fuel cost over recovered balance during 2012 was primarily due to lower than expected fuel costs and purchased power energy expenses. At December 31, 2012 and 2011, the over recovered fuel balance was approximately $17.1 million and $9.9 million, respectively, which is included in other regulatory liabilities, current in the balance sheets.
Purchased Power Capacity Recovery
The Company has established purchased power capacity recovery cost rates as approved by the Florida PSC. If the projected year-end purchased power capacity cost over or under recovery balance exceeds 10% of the projected purchased power capacity revenue applicable for the period, the Company is required to notify the Florida PSC and indicate if an adjustment to the purchased power capacity cost recovery factor is being requested.
At December 31, 2012, the Company had an under recovered purchased power capacity balance of approximately $0.8 million, which is included in under recovered regulatory clause revenues in the balance sheets. At December 31, 2011, the Company had an over recovered purchased power capacity balance of approximately $8.0 million, which is included in other regulatory liabilities, current in the balance sheets.
Environmental Cost Recovery
The Florida Legislature adopted legislation for an environmental cost recovery clause, which allows an electric utility to petition the Florida PSC for recovery of prudent environmental compliance costs that are not being recovered through base rates or any other recovery mechanism. Such environmental costs include operations and maintenance expenses, emissions allowance expense, depreciation, and a return on net average investment. This legislation also allows recovery of costs incurred as a result of an agreement between the Company and the FDEP for the purpose of ensuring compliance with ozone ambient air quality standards adopted by the EPA.
In 2007, the Florida PSC voted to approve a stipulation among the Company, the Office of Public Counsel, and the Florida Industrial Power Users Group regarding the Company's plan for complying with certain federal and state regulations addressing air quality. The Company's environmental compliance plan as filed in 2007 contemplated implementation of specific projects identified in the plan from 2007 through 2018. The stipulation covers all elements of the original plan that were committed for implementation at the time of the stipulation. The Florida PSC's approval of the stipulation also required the Company to file annual updates to the plan and outlined a process for approval of additional elements in the plan when they became committed projects. In the 2010 update filing, the Company identified several elements of the updated plan that the Company had decided to implement. Following the process outlined in the original approved stipulation, these additional projects were approved by the Florida PSC later in 2010. The Florida PSC acknowledged that the costs of the approved projects associated with the Company's Clean Air Interstate Rule and Clean Air Visibility Rule compliance plans are eligible for recovery through the environmental cost recovery clause.
Annually, the Company seeks recovery of projected costs including any true-up amounts from prior periods. At December 31, 2012, the under recovered environmental balance was approximately $1.9 million, which is included in under recovered regulatory clause revenues in the balance sheets. At December 31, 2011, the over recovered environmental balance was approximately $10.0 million, which is included in other regulatory liabilities, current in

the balance sheets.

On April 3, 2012, the Mississippi PSC approved Mississippi Power's request for a certificate of public convenience and necessity to construct a flue gas desulfurization system (scrubber) on Plant Daniel Units 1 and 2. On May 3, 2012, the Sierra Club filed a notice of appeal of the order with the Chancery Court of Harrison County, Mississippi. These units are jointly owned by Mississippi Power and the Company, with 50% ownership each. The estimated total cost of the project is approximately $660 million, excluding AFUDC, and it is scheduled for completion in December 2015. The Company's portion of the cost is expected to be recovered through the environmental cost recovery clause. The ultimate outcome of this matter cannot be determined at this time.

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Energy Conservation Cost Recovery

Every five years, the Florida PSC establishes new numeric conservation goals covering a 10-year period for utilities to reduce annual energy and seasonal peak demand using demand-side management (DSM) programs. After the goals are established, utilities develop plans and programs to meet the approved goals. The costs for these programs are recovered through rates established annually in the energy conservation cost recovery (ECCR) clause.

The most recent goal setting process established new DSM goals for the period 2010 through 2019. The new goals are significantly higher than the goals established in the previous five-year cycle due to a change in the cost-effectiveness test on which the Florida PSC relies to set the goals. The DSM program standards were approved in April 2011, which allow the Company to implement its DSM programs designed to meet the new goals. Several of these new programs were implemented in June 2011 and the costs related to these programs are reflected in the 2012 ECCR factor approved by the Florida PSC. Higher cost recovery rates and achievement of the new DSM goals may result in reduced sales of electricity which could negatively impact results of operations, cash flows, and financial condition if base rates cannot be adjusted on a timely basis.

At December 31, 2012 and 2011, the under recovered energy conservation balance was approximately $0.8 million and $3.1 million, respectively, which is included in under recovered regulatory clause revenues in the balance sheets.

4. JOINT OWNERSHIP AGREEMENTS

The Company and Mississippi Power jointly own Plant Daniel Units 1 and 2, which together represent capacity of 1,000 MWs. Plant Daniel is a generating plant located in Jackson County, Mississippi. In accordance with the operating agreement, Mississippi Power acts as the Company's agent with respect to the construction, operation, and maintenance of these units.

The Company and Georgia Power jointly own the 818 MWs capacity Plant Scherer Unit 3. Plant Scherer is a generating plant located near Forsyth, Georgia. In accordance with the operating agreement, Georgia Power acts as the Company's agent with respect to the construction, operation, and maintenance of the unit.

The Company's proportionate share of expenses related to both plants is included in the corresponding operating expense accounts in the statements of income and the Company is responsible for providing its own financing.

At December 31, 2012, the Company's percentage ownership and investment in these jointly owned facilities were as follows:

	Plant Scherer Unit 3 (coal)	Plant Daniel Units 1 & 2 (coal)
	(in thousands)	
Plant in service	$373,576 [(a)]	$277,440
Accumulated depreciation	117,181	165,120
Construction work in progress	8,763	69,774
Ownership	25 %	50 %

(a) Includes net plant acquisition adjustment of $2.3 million.

The Company's proportionate share of its plant operating expenses is included in the corresponding operating expenses in the statements of income and the Company is responsible for providing its own financing.

5. INCOME TAXES

On behalf of the Company, Southern Company files a consolidated federal income tax return and 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 Florida. Under a joint consolidated income tax allocation agreement, each 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 Internal Revenue Service (IRS) regulations, each company is jointly and severally liable for the federal tax liability.

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Current and Deferred Income Taxes

Details of income tax provisions are as follows:

	2012	2011	2010
	(in thousands)		
Federal -			
Current	$(92,610)	$(1,548)	$(14,115)
Deferred	161,096	56,087	77,452
	68,486	54,539	63,337
State -			
Current	(2,484)	(412)	2,948
Deferred	13,209	7,141	5,229
	10,725	6,729	8,177
Total	$79,211	$61,268	$71,514

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:

	2012	2011
	(in thousands)	
Deferred tax liabilities-		
Accelerated depreciation	$696,502	$496,392
Pension and other employee benefits	28,579	25,268
Regulatory assets associated with employee benefit obligations	57,279	44,871
Regulatory assets associated with asset retirement obligations	6,502	4,345
Other	16,019	14,804
Total	804,881	585,680
Deferred tax assets-		
Federal effect of state deferred taxes	20,656	16,684
Postretirement benefits	17,905	16,769
Fuel recovery clause	6,922	2,531
Pension and other employee benefits	61,939	49,116
Property reserve	13,773	13,159
Other comprehensive loss	993	1,353
Asset retirement obligations	6,502	4,345
Alternative minimum tax carryforward	938	7,151
Other	28,273	20,191
Total	157,901	131,299
Net deferred tax liabilities	646,980	454,381
Portion included in current assets (liabilities), net	1,972	4,597
Accumulated deferred income taxes	$648,952	$458,978

At December 31, 2012, the tax-related regulatory assets to be recovered from customers were $50.5 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 AFUDC. At December 31, 2012, the tax-related regulatory liabilities to be credited to customers were $6.5 million. These liabilities are primarily attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and to unamortized investment tax credits.

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In accordance with regulatory requirements, deferred investment tax credits 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 $1.4 million in 2012, $1.3 million in 2011, and $1.5 million in 2010. At December 31, 2012, all investment tax credits 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 to be placed in service in 2013). The application of the bonus depreciation provisions in the Tax Relief Act significantly increased deferred tax liabilities related to accelerated depreciation.
Effective Tax Rate
A reconciliation of the federal statutory income tax rate to the effective income tax rate is as follows:

	2012	2011	2010
Federal statutory rate	35.0 %	35.0 %	35.0 %
State income tax, net of federal deduction	3.3	2.5	2.7
Non-deductible book depreciation	0.5	0.5	0.3
Differences in prior years' deferred and current tax rates	(0.2)	(0.3)	(0.3)
AFUDC equity	(0.9)	(2.0)	(1.3)
Other, net	(0.2)	(0.2)	(0.5)
Effective income tax rate	37.5 %	35.5 %	35.9 %

The increase in the 2012 effective tax rate is primarily the result of a decrease in AFUDC equity, which is not taxable, and a decrease in state tax credits.
Unrecognized Tax Benefits
For 2012, the total amount of unrecognized tax benefits increased by $2.1 million, resulting in a balance of $5.0 million as of December 31, 2012.
Changes during the year in unrecognized tax benefits were as follows:

	2012	2011	2010
	(in thousands)		
Unrecognized tax benefits at beginning of year	$2,892	$3,870	$1,639
Tax positions from current periods	2,630	540	1,027
Tax positions from prior periods	515	(1,518)	1,204
Reductions due to settlements	(1,030)	—	—
Balance at end of year	$5,007	$2,892	$3,870

The tax positions increase from current periods for 2012 relates primarily to the tax accounting method change for repairs-generation assets. The tax positions increase from prior periods for 2012 also relates primarily to the tax accounting method change for repairs-generation assets. See "Tax Method of Accounting for Repairs" herein for additional information. The American Jobs Creation Act of 2004 created a tax deduction for a portion of income attributable to U.S. production activities as defined in Section 199 of the Internal Revenue Code (production activities deduction). The reductions due to settlements for 2012 relate to a settlement with the IRS of the calculation methodology for the production activities deduction.
The impact on the Company's effective tax rate, if recognized, was as follows:

	2012	2011	2010
	(in thousands)		
Tax positions impacting the effective tax rate	$45	$1,804	$1,826
Tax positions not impacting the effective tax rate	4,962	1,088	2,044

Balance of unrecognized tax benefits	$5,007	$2,892	$3,870

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The tax positions impacting the effective tax rate for 2012 relate primarily to the research and development credit. 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:

	2012	2011	2010
	(in thousands)		
Interest accrued at beginning of year	$283	$210	$90
Interest reclassified due to settlements	(283)	—	—
Interest accrued during the year	—	73	120
Balance at end of year	$—	$283	$210

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 associated with a majority of the Company's unrecognized tax positions will significantly increase or decrease within 12 months. The resolution of the tax accounting method change for repairs-generation assets, as well as the conclusion or settlement of 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 audited and closed all of Southern Company's consolidated federal income tax returns prior to 2009 and has settled its audits of Southern Company's consolidated federal income tax returns for 2009 and 2010, in principle, pending final approval. Additionally, the IRS has audited and closed Southern Company's 2011 consolidated federal income tax return. For tax years 2010 through 2013, Southern Company is a participant in the Compliance Assurance Process of the IRS. The audits for the Company's state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2007.

Tax Method of Accounting for Repairs

Southern Company submitted a tax accounting method change related to the deductibility of repair costs associated with its subsidiaries' generation, transmission, and distribution systems effective for the 2009 consolidated federal income tax return in 2010. In August 2011, the IRS issued a revenue procedure, which provides a safe harbor method of accounting that taxpayers may use to determine eligible repair costs for transmission and distribution property. The IRS continues to work with the utility industry in an effort to define eligible repair costs for generation assets in a consistent manner for all utilities. 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. The utility industry anticipates more detailed guidance concerning these regulations. Due to the uncertainty regarding the ultimate resolution of the repair costs for generation assets, an unrecognized tax position has been recorded for the tax accounting method change for repairs-generation assets. The ultimate outcome of this matter cannot be determined at this time; however, it is not expected to materially impact net income.

6. FINANCING

Securities Due Within One Year

Approximately $60 million will be required through December 31, 2013 to fund maturities of long-term debt. Maturities from 2014 through 2017 applicable to total long-term debt are as follows: $75 million in 2014; $110 million in 2016; and $85 million in 2017. There are no scheduled maturities in 2015.

Senior Notes

At December 31, 2012 and 2011, the Company had a total of $945 million and $936.4 million of senior notes outstanding, respectively. These senior notes are effectively subordinate to all secured debt of the Company, which totals approximately $41 million at December 31, 2012.

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In May 2012, the Company issued $100 million aggregate principal amount of Series 2012A 3.10% Senior Notes due May 15, 2022. The net proceeds from the sale of the Series 2012A Senior Notes were used to redeem all of approximately $61 million aggregate principal amount of the Company's Series F 5.60% Senior Insured Quarterly Notes due April 1, 2033 and $30 million aggregate principal amount of the Company's Series H 5.25% Senior Notes due July 15, 2033, to repay a portion of the Company's outstanding short-term indebtedness, and for general corporate purposes, including the Company's continuous construction program.

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, 2012 and 2011 was $309 million.

In November 2012, the Mississippi Business Finance Corporation issued $13 million aggregate principal amount of Mississippi Business Finance Corporation Solid Waste Disposal Facilities Revenue Refunding Bonds, Series 2012 (Gulf Power Company Project), due November 1, 2042 for the benefit of the Company. The proceeds were used in December 2012 to redeem the Mississippi Business Finance Corporation Solid Waste Disposal Facilities Revenue Refunding Bonds, Series 2002 (Gulf Power Company Project), due September 1, 2028.

Outstanding Classes of Capital Stock

The Company currently has preferred stock, Class A preferred stock, preference stock, and common stock authorized. The Company's preferred stock and Class A preferred stock, without preference between classes, rank senior to the Company's preference stock and common stock with respect to payment of dividends and voluntary or involuntary dissolution. No shares of preferred stock or Class A preferred stock were outstanding at December 31, 2012. The Company's preference stock ranks senior to the common stock with respect to the payment of dividends and voluntary or involuntary dissolution. Certain series of the preference stock are subject to redemption at the option of the Company on or after a specified date (typically five or 10 years after the date of issuance) at a redemption price equal to 100% of the liquidation amount of the preference stock. In addition, one series of the preference stock may be redeemed earlier at a redemption price equal to 100% of the liquidation amount plus a make-whole premium based on the present value of the liquidation amount and future dividends.

In January 2012, the Company issued to Southern Company 400,000 shares of the Company's common stock, without par value, and realized proceeds of $40 million. Subsequent to December 31, 2012, the Company issued to Southern Company 400,000 shares of the Company's common stock, without par value, and realized proceeds of $40 million. The proceeds were used to repay a portion of the Company's short-term debt and for other general corporate purposes, including the Company's continuous construction program.

Dividend Restrictions

The Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

Assets Subject to Lien

The Company has granted a lien on its property at Plant Daniel in connection with the issuance of two series of pollution control revenue bonds with an outstanding principal amount of $41 million. There are no agreements or other arrangements among the Southern Company system companies under which the assets of one company have been pledged or otherwise made available to satisfy obligations of Southern Company or any of its subsidiaries.

Bank Credit Arrangements

At December 31, 2012, committed credit arrangements with banks were as follows:

Expires[(a)]	Executable Term-Loans	Due Within One Year

2013	2014	Total	Unused	One Year	Two Years	Term Out	No Term Out
$80	$195	$275	$275	$45	$—	$45	$35

(a) No credit arrangements expire after 2014.

NOTES (continued)
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During 2012, the Company renewed a $30 million credit arrangement and changed the terms of the credit arrangement so that it expires after two years instead of one year, which is reflected in the table above. The Company expects to renew its credit arrangements, as needed, prior to expiration. Of the $275 million of unused credit arrangements, $69 million provides support for variable rate pollution control revenue bonds and $206 million was available for liquidity support for the Company's commercial paper program and for other general corporate purposes. Most of 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.

Most of those credit arrangements with banks contain covenants that limit the Company's debt level to 65% of total capitalization, as defined in the arrangements. At December 31, 2012, the Company was in compliance with these covenants.

In addition, the credit arrangements typically contain cross default provisions that are restricted only to indebtedness of the Company. The Company is currently in compliance with all such covenants.

For short-term cash needs, the Company borrows primarily through a commercial paper program that has the liquidity support of the Company's committed bank credit arrangements. The Company 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 included in notes payable on the balance sheets were as follows:

	Short-term Debt at the End of the Period [(a)]	
	Amount Outstanding	Weighted Average Interest Rate
	(in millions)	
December 31, 2012:		
Commercial paper	$124	0.3%
December 31, 2011:		
Commercial paper	$111	0.2%

(a) Excludes notes payable related to other energy service contracts of $3.2 million and $3.6 million for the periods ended December 31, 2012 and 2011, respectively.

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 of fossil fuel which are not recognized on the balance sheets. In 2012, 2011, and 2010, the Company incurred fuel expense of $544.9 million, $662.3 million, and $742.3 million, the majority of which was purchased under long-term commitments. The Company expects that a substantial amount of its future fuel needs will continue to be purchased under long-term commitments.

In addition, the Company has entered into various long-term commitments for the purchase of capacity, energy, and transmission, some of which are accounted for as operating leases. The energy-related costs associated with PPAs are recovered through the fuel cost recovery clause. The capacity and transmission-related costs associated with PPAs are recovered through the purchased power capacity cost recovery clause. Capacity expense under purchased power agreements accounted for as operating leases was $24.6 million, $25.1 million, and $25.1 million for 2012, 2011, and 2010, respectively.

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Estimated total minimum long-term commitments at December 31, 2012 were as follows:

	Operating Lease PPAs
	(in millions)
2013	$ 24.7
2014	52.9
2015	78.6
2016	78.7
2017	78.8
2018 and thereafter	428.1
Total	$ 741.8

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. The credit rating of Southern Power is currently below that of the traditional operating companies. 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 operating lease agreements with various terms and expiration dates. Total rent expense was $20.1 million, $21.9 million, and $23.1 million for 2012, 2011, and 2010, respectively.

Estimated total minimum lease payments under operating leases at December 31, 2012 were as follows:

	Minimum Lease Payments		
	Barges & Railcars	Other	Total
	(in millions)		
2013	$18.6	$0.3	$18.9
2014	17.2	0.3	17.5
2015	1.1	0.1	1.2
2016	0.9	0.1	1.0
2017	1.0	0.1	1.1
2018 and thereafter	—	—	—
Total	$38.8	$0.9	$39.7

The Company and Mississippi Power jointly entered into operating lease agreements for aluminum railcars for the transportation of coal to Plant Daniel. The Company has the option to purchase the railcars at the greater of lease termination value or fair market value or to renew the leases at the end of each lease term. The Company and Mississippi Power also have separate lease agreements for other railcars that do not include purchase options. The Company's share of the lease costs, charged to fuel inventory and recovered through the fuel cost recovery clause, was $3.6 million in 2012, $2.6 million in 2011, and $3.5 million in 2010. The Company's annual railcar lease payments for 2013 through 2017 will average approximately $1.6 million. The Company has no lease payment obligations for the period 2018 and thereafter.

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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, 2012, there were 218 current and former employees of the Company participating in the stock option program, and there were 39 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. For certain stock option awards, a change in control will provide accelerated vesting.

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	2012	2011	2010
Expected volatility	17.7%	17.5%	17.4%
Expected term (in years)	5.0	5.0	5.0
Interest rate	0.9%	2.3%	2.4%
Dividend yield	4.2%	4.8%	5.6%
Weighted average grant-date fair value	$3.39	$3.23	$2.23

The Company's activity in the stock option program for 2012 is summarized below:

	Shares Subject to Option	Weighted Average Exercise Price
Outstanding at December 31, 2011	1,498,663	$33.75
Granted	244,607	44.43
Exercised	(353,749)	31.97
Cancelled	(606)	42.08
Outstanding at December 31, 2012	1,388,915	$36.08
Exercisable at December 31, 2012	884,888	$34.02

The number of stock options vested, and expected to vest in the future, as of December 31, 2012, was not significantly different from the number of stock options outstanding at December 31, 2012 as stated above. As of December 31, 2012, 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 $9.7 million and $7.8 million, respectively.

As of December 31, 2012, there was $0.3 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, 2012, 2011, and 2010, total compensation cost for stock option awards recognized in income was $0.7 million, $0.7 million, and $0.8 million, respectively, with the related tax benefit also recognized in income of $0.3 million, $0.3 million, and $0.3 million, respectively.

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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, 2012, 2011, and 2010 was $3.8 million, $3.2 million, and $1.6 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $1.5 million, $1.2 million, and $0.6 million for the years ended December 31, 2012, 2011, and 2010, 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	2012	2011	2010
Expected volatility	16.0%	19.2%	20.7%
Expected term (in years)	3.0	3.0	3.0
Interest rate	0.4%	1.4%	1.4%
Annualized dividend rate	$1.89	$1.82	$1.75
Weighted average grant-date fair value	$41.99	$35.97	$30.13

Total unvested performance share units outstanding as of December 31, 2011 were 66,662. During 2012, 29,444 performance share units were granted, 26,738 performance share units were vested, and 563 performance share units were forfeited resulting in 68,805 unvested units outstanding at December 31, 2012. In January 2013, the vested performance share award units were converted into 36,105 shares outstanding at a share price of $43.05 for the three-year performance and vesting period ended December 31, 2012.

For the years ended December 31, 2012, 2011, and 2010, total compensation cost for performance share units recognized in income was $1.0 million, $0.7 million, and $0.3 million, respectively, with the related tax benefit also recognized in income of $0.4 million, $0.3 million, and $0.1 million, respectively. As of December 31, 2012, there was $1.0 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.

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9. FAIR VALUE MEASUREMENTS

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

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

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

As of December 31, 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 thousands)			
Assets:				
Energy-related derivatives	$—	$4,358	$—	$4,358
Cash equivalents	15,231	—	—	15,231
Total	$15,231	$4,358	$—	$19,589
Liabilities:				
Energy-related derivatives	$—	$27,112	$—	$27,112

As of December 31, 2011, 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, 2011:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in thousands)			
Assets:				
Energy-related derivatives	$—	$198	$—	$198
Cash equivalents	13,949	—	—	13,949
Total	$13,949	$198	$—	$14,147
Liabilities:				
Energy-related derivatives	$—	$40,983	$—	$40,983

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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 London Interbank Offered Rate interest rates. See Note 10 for additional information on how these derivatives are used.
As of December 31, 2012 and 2011, 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, 2012:	(in thousands)			
Cash equivalents:				
Money market funds	$15,231	None	Daily	Not applicable
As of December 31, 2011:				
Cash equivalents:				
Money market funds	$13,949	None	Daily	Not applicable

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, 2012 and 2011, other financial instruments for which the carrying amount did not equal fair value were as follows:

	Carrying Amount	Fair Value
	(in thousands)	
Long-term debt:		
2012	$1,245,870	$1,367,404
2011	$1,235,447	$1,350,237

The fair values are determined using Level 2 measurements and are based on quoted market prices for the same or similar issues or on the current rates offered to the Company.
10. DERIVATIVES
The Company is exposed to market risks, primarily commodity price risk and interest rate risk. To manage the volatility attributable to these exposures, the Company nets its exposures, where possible, to take advantage of natural offsets and may enter into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a gross basis.
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 Florida PSC, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility.

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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 two methods:

- Regulatory Hedges — Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the Company's fuel hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the fuel cost recovery clause.
- 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, 2012, 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:

Gas Net Purchased mmBtu* (in thousands)	Longest Hedge Date	Longest Non-Hedge Date
70,510	2017	—

* mmBtu — million British thermal units

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, 2012, there were no interest rate derivatives outstanding.

The estimated pre-tax losses that will be reclassified from OCI to interest expense for the 12-month period ending December 31, 2013 are $0.8 million. The Company has deferred gains and losses that are expected to be amortized into earnings through 2020.

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Derivative Financial Statement Presentation and Amounts
At December 31, 2012 and 2011, the fair value of energy-related derivatives was reflected in the balance sheets as follows:

Derivative Category	Asset Derivatives Balance Sheet Location	2012	2011	Liability Derivatives Balance Sheet Location	2012	2011
		(in thousands)			(in thousands)	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	$1,293	$154	Liabilities from risk management activities	$16,529	$22,786
	Other deferred charges and assets	3,065	44	Other deferred credits and liabilities	10,583	18,197
Total derivatives designated as hedging instruments for regulatory purposes		$4,358	$198		$27,112	$40,983
Derivatives not designated as hedging instruments						
Energy-related derivatives:	Other current assets	$—	$—	Liabilities from risk management activities	$—	$—
Total		$4,358	$198		$27,112	$40,983

All derivative instruments are measured at fair value. See Note 9 for additional information.
At December 31, 2012 and 2011, 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	2012	2011	Unrealized Gains Balance Sheet Location	2012	2011
		(in thousands)			(in thousands)	
Energy-related derivatives:	Other regulatory assets, current	$(16,529)	$(22,786)	Other regulatory liabilities, current	$1,293	$154
	Other regulatory assets, deferred	(10,583)	(18,197)	Other regulatory liabilities, deferred	3,065	44
Total energy-related derivative gains (losses)		$(27,112)	$(40,983)		$4,358	$198

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For the years ended December 31, 2012, 2011, and 2010, the pre-tax effects of interest rate derivatives designated as cash flow hedging instruments on the statements of income were as follows:

Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Recognized in OCI on Derivative (Effective Portion)			Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)			
					Amount		
Derivative Category	2012	2011	2010	Statements of Income Location	2012	2011	2010
	(in thousands)				(in thousands)		
Interest rate derivatives	$—	$—	$(1,405)	Interest expense, net of amounts capitalized	$(933)	$(933)	$(974)

There was no material ineffectiveness recorded in earnings for any period presented.
For the years ended December 31, 2012, 2011, and 2010, the pre-tax effects of energy-related derivatives not designated as hedging instruments on the statements of income were not material.
Contingent Features
The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain affiliated companies. At December 31, 2012, the fair value of derivative liabilities with contingent features was $4 million.
At December 31, 2012, 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 $15 million. 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.

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11. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)
Summarized quarterly financial information for 2012 and 2011 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preference Stock
	(in thousands)		
March 2012	$316,245	$49,098	$20,666
June 2012	370,208	71,465	34,963
September 2012	421,819	93,813	47,754
December 2012	331,490	53,818	22,549
March 2011	$324,608	$32,044	$11,691
June 2011	399,265	67,387	33,352
September 2011	468,030	81,454	41,217
December 2011	327,909	43,839	18,745

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

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SELECTED FINANCIAL AND OPERATING DATA 2008-2012
Gulf Power Company 2012 Annual Report

	2012	2011	2010	2009	2008
Operating Revenues (in thousands)	$1,439,762	$1,519,812	$1,590,209	$1,302,229	$1,387,203
Net Income After Dividends on Preference Stock (in thousands)	$125,932	$105,005	$121,511	$111,233	$98,345
Cash Dividends on Common Stock (in thousands)	$115,800	$110,000	$104,300	$89,300	$81,700
Return on Average Common Equity (percent)	10.92	9.55	11.69	12.18	12.66
Total Assets (in thousands)	$4,177,402	$3,871,881	$3,584,939	$3,293,607	$2,879,025
Gross Property Additions (in thousands)	$325,237	$337,830	$285,379	$450,421	$390,744
Capitalization (in thousands):					
Common stock equity	$1,180,742	$1,124,948	$1,075,036	$1,004,292	$822,092
Preference stock	97,998	97,998	97,998	97,998	97,998
Long-term debt	1,185,870	1,235,447	1,114,398	978,914	849,265
Total (excluding amounts due within one year)	$2,464,610	$2,458,393	$2,287,432	$2,081,204	$1,769,355
Capitalization Ratios (percent):					
Common stock equity	47.9	45.8	47.0	48.3	46.5
Preference stock	4.0	4.0	4.3	4.7	5.5
Long-term debt	48.1	50.2	48.7	47.0	48.0
Total (excluding amounts due within one year)	100.0	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	379,922	378,248	376,561	374,091	373,595
Commercial	53,808	53,450	53,263	53,272	53,548
Industrial	264	273	272	279	287
Other	577	565	562	512	499
Total	434,571	432,536	430,658	428,154	427,929
Employees (year-end)	1,416	1,424	1,330	1,365	1,342

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SELECTED FINANCIAL AND OPERATING DATA 2008-2012 (continued)
Gulf Power Company 2012 Annual Report

	2012	2011	2010	2009	2008
Operating Revenues (in thousands):					
Residential	$609,454	$637,352	$707,196	$588,073	$581,723
Commercial	389,936	408,389	439,468	376,125	369,625
Industrial	140,490	158,367	157,591	138,164	165,564
Other	4,591	4,382	4,471	4,206	3,854
Total retail	1,144,471	1,208,490	1,308,726	1,106,568	1,120,766
Wholesale — non-affiliates	106,881	133,555	109,172	94,105	97,065
Wholesale — affiliates	123,636	111,346	110,051	32,095	106,989
Total revenues from sales of electricity	1,374,988	1,453,391	1,527,949	1,232,768	1,324,820
Other revenues	64,774	66,421	62,260	69,461	62,383
Total	$1,439,762	$1,519,812	$1,590,209	$1,302,229	$1,387,203
Kilowatt-Hour Sales (in thousands):					
Residential	5,053,724	5,304,769	5,651,274	5,254,491	5,348,642
Commercial	3,858,521	3,911,399	3,996,502	3,896,105	3,960,923
Industrial	1,725,121	1,798,688	1,685,817	1,727,106	2,210,597
Other	25,267	25,430	25,602	25,121	23,237
Total retail	10,662,633	11,040,286	11,359,195	10,902,823	11,543,399
Wholesale — non-affiliates	977,395	2,012,986	1,675,079	1,813,592	1,816,839
Wholesale — affiliates	4,369,964	2,607,873	2,436,883	870,470	1,871,158
Total	16,009,992	15,661,145	15,471,157	13,586,885	15,231,396
Average Revenue Per Kilowatt-Hour (cents):					
Residential	12.06	12.01	12.51	11.19	10.88
Commercial	10.11	10.44	11.00	9.65	9.33
Industrial	8.14	8.80	9.35	8.00	7.49
Total retail	10.73	10.95	11.52	10.15	9.71
Wholesale	4.31	5.30	5.33	4.70	5.53
Total sales	8.59	9.28	9.88	9.07	8.70
Residential Average Annual Kilowatt-Hour Use Per Customer	13,303	14,028	15,036	14,049	14,274
Residential Average Annual Revenue Per Customer	$1,604	$1,685	$1,882	$1,572	$1,552
Plant Nameplate Capacity Ratings (year-end) (megawatts)	2,663	2,663	2,663	2,659	2,659
Maximum Peak-Hour Demand (megawatts):					
Winter	2,130	2,485	2,544	2,310	2,360
Summer	2,344	2,527	2,519	2,538	2,533
Annual Load Factor (percent)	56.3	54.5	56.1	53.8	56.7
Plant Availability Fossil-Steam (percent)*	82.5	84.7	94.7	89.7	88.6
Source of Energy Supply (percent):					
Coal	34.6	49.4	64.6	61.7	77.3

Gas	23.5	24.0	17.8	28.0	15.3
Purchased power —					
From non-affiliates	40.2	22.3	13.2	2.2	2.6
From affiliates	1.7	4.3	4.4	8.1	4.8
Total	100.0	100.0	100.0	100.0	100.0

* Beginning in 2012, plant availability is calculated as a weighted equivalent availability.

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MISSISSIPPI POWER COMPANY
FINANCIAL SECTION

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Mississippi Power Company 2012 Annual Report

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

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in Internal Control—Integrated Framework 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, 2012.

/s/ Edward Day, VI
Edward Day, VI
President and Chief Executive Officer
/s/ Moses H. Feagin
Moses H. Feagin
Vice President, Treasurer, and Chief Financial Officer
February 27, 2013

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM
To the Board of Directors of
Mississippi Power Company

We have audited the accompanying balance sheets and statements of capitalization of Mississippi Power Company (the Company) (a wholly owned subsidiary of The Southern Company) as of December 31, 2012 and 2011, 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, 2012. 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-389 to II-439) present fairly, in all material respects, the financial position of Mississippi Power Company as of December 31, 2012 and 2011, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 27, 2013

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Mississippi Power Company 2012 Annual Report
OVERVIEW
Business Activities
Mississippi Power Company (the Company) operates as a vertically integrated utility providing electricity to retail customers within its traditional service territory located within the State of Mississippi and to wholesale customers in the Southeast.
Many factors affect the opportunities, challenges, and risks of the Company's business of 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 rising 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. The Company 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 Company for the foreseeable future.
The Company's retail base rates are set under the Performance Evaluation Plan (PEP), a rate plan approved by the Mississippi Public Service Commission (PSC). PEP was designed with the objective to reduce the impact of rate changes on customers and provide incentives for the Company to keep customer prices low and customer satisfaction and reliability high.
In 2010, the Mississippi PSC issued a certificate of public convenience and necessity (CPCN) authorizing the acquisition, construction, and operation of a new integrated coal gasification combined cycle (IGCC) electric generating plant located in Kemper County, Mississippi (Kemper IGCC), which is scheduled to be placed into service in 2014.
On January 24, 2013, the Company and the Mississippi PSC entered into a settlement agreement (Settlement Agreement) that (i) establishes the process for resolving matters regarding cost recovery related to the Kemper IGCC for the purpose of mitigating risks to the Company and its customers and expediting the regulatory process associated with future rate filings required under the Settlement Agreement and (ii) resolves the Company's appeal before the Mississippi Supreme Court related to the new Certificated New Plant-A (CNP-A) rate schedule and stipulated rate increase submitted to the Mississippi PSC on June 14, 2012. The ultimate outcome of this matter cannot be determined at this time. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information.
In October 2011, at the completion of the ten year operating lease, the Company purchased the combined cycle generating Units 3 and 4 at Plant Daniel (Plant Daniel Units 3 and 4) for $84.8 million in cash and the assumption of $270 million face value of debt obligations of the lessor related to Plant Daniel Units 3 and 4. See FINANCIAL CONDITION AND LIQUIDITY – "Purchase of the Plant Daniel Combined Cycle Generating Units" herein for additional information.
Key Performance Indicators
The Company continues to focus on several key performance indicators. These indicators are used to measure the Company's performance for customers and employees.
In recognition that the Company's long-term financial success is dependent upon how well it satisfies its customers' needs, the Company's retail base rate mechanism, PEP, includes performance indicators that directly tie customer service indicators to the Company's allowed return. PEP measures the Company's performance on a 10-point scale as a weighted average of results in three areas: average customer price, as compared to prices of other regional utilities (weighted at 40%); service reliability, measured in percentage of time customers had electric service (40%); and customer satisfaction, measured in a survey of residential customers (20%). See Note 3 to the financial statements under "Retail Regulatory Matters – Performance Evaluation Plan" for more information on PEP.

In addition to the PEP performance indicators, the Company focuses on other performance measures, including broader measures of customer satisfaction, plant availability, system reliability, and net income after dividends on preferred 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 2012 fossil/hydro Peak Season EFOR was better than the target, excluding the impact of Hurricane Isaac in August 2012. 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 2012 performance was better than the target for these reliability measures.

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Mississippi Power Company 2012 Annual Report

Net income after dividends on preferred stock is the primary measure of the Company's financial performance. The Company was below target for 2012 net income after dividends on preferred stock primarily due to lower retail revenue under PEP and the Mississippi PSC denial of the 2012 rate recovery filings for the Kemper IGCC, partially offset by lower operations and maintenance expenses and higher allowance for funds used during construction (AFUDC) related to the construction of the Kemper IGCC, which began in 2010. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Performance Evaluation Plan" and FUTURE EARNINGS POTENTIAL – "PSC Matters – Certificated New Plant" herein for additional information.

The Company's 2012 results compared with its targets for some of these key indicators are reflected in the following chart:

Key Performance Indicator	2012 Target Performance	2012 Actual Performance
Customer Satisfaction	Top quartile in customer surveys	Top quartile overall and in all segments
Peak Season EFOR*	4.99% or less	0.5%
Net income after dividends on preferred stock	$156.9 million	$148.1 million

*Excluding impact of Hurricane Isaac

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

Management continues to emphasize the importance of performing well and employees continue to demonstrate their commitment to achieving or exceeding management's expectations.

Earnings

The Company's net income after dividends on preferred stock was $148.1 million in 2012 compared to $94.2 million in 2011. The 57.3% increase in 2012 was primarily the result of increases in AFUDC equity related to the construction of the Kemper IGCC which began in 2010, a decrease in operations and maintenance expenses, and an increase in territorial base revenues primarily due to a wholesale base rate increase effective April 1, 2012. This increase in net income after dividends on preferred stock was partially offset by an increase in interest expense, net of amounts capitalized. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information regarding the Kemper IGCC.

The Company's net income after dividends on preferred stock was $94.2 million in 2011 compared to $80.2 million in 2010. The 17.4% increase in 2011 was primarily the result of increases in AFUDC equity related to the construction of the Kemper IGCC. This increase in net income after dividends on preferred stock was partially offset by decreases in retail base revenues resulting from closer to normal weather in 2011 compared to 2010 and increased depreciation and amortization.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Mississippi Power Company 2012 Annual Report

RESULTS OF OPERATIONS
A condensed statement of income follows:

	Amount	Increase (Decrease) from Prior Year	
	2012	2012	2011
	(in millions)		
Operating revenues	$1,036.0	$(76.9)	$(30.2)
Fuel	411.2	(79.2)	(11.4)
Purchased power	55.1	(16.7)	(11.9)
Other operations and maintenance	228.7	(37.7)	(1.7)
Depreciation and amortization	86.6	6.2	3.5
Taxes other than income taxes	79.4	9.3	0.3
Total operating expenses	861.0	(118.1)	(21.2)
Operating income	175.0	41.2	(9.0)
Allowance for equity funds used during construction	64.8	40.1	20.9
Interest income	0.7	(0.6)	1.1
Interest expense, net of amounts capitalized	40.8	19.1	(0.7)
Other income (expense), net	0.5	0.5	(3.8)
Income taxes	50.4	8.2	(4.1)
Net income	149.8	53.9	14.0
Dividends on preferred stock	1.7	—	—
Net income after dividends on preferred stock	$148.1	$53.9	$14.0

Operating Revenues

Operating revenues for 2012 were $1.0 billion, reflecting a $76.9 million decrease from 2011. Details of the Company's operating revenues in 2012 and the prior year were as follows:

	Amount	
	2012	2011
	(in millions)	
Retail — prior year	$792.5	$797.9
Estimated change in —		
Rates and pricing	(2.0)	0.5
Sales growth (decline)	9.0	2.3
Weather	(9.8)	(8.9)
Fuel and other cost recovery	(42.2)	0.7
Retail — current year	747.5	792.5
Wholesale revenues —		
Non-affiliates	255.5	273.2
Affiliates	16.4	30.4
Total wholesale revenues	271.9	303.6
Other operating revenues	16.6	16.8
Total operating revenues	$1,036.0	$1,112.9
Percent change	(6.9)%	(2.6)%

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Mississippi Power Company 2012 Annual Report

Total retail revenues for 2012 decreased 5.7% compared to 2011 primarily as a result of lower energy sales primarily due to milder weather and lower fuel cost recovery revenues in 2012 compared to 2011. Total retail revenues for 2011 decreased 0.7% compared to 2010 primarily as a result of lower energy sales due to closer to normal weather in 2011 compared to 2010. 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 Company include provisions to adjust billings for fluctuations in fuel costs, including the energy component of purchased power costs. Under these provisions, fuel revenues generally equal fuel expenses, including the energy component of purchased power costs, and do not affect net income. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" herein for additional information. The fuel and other cost recovery revenues decreased in 2012 compared to 2011 primarily as a result of lower recoverable fuel costs, partially offset by an increase in revenues related to ad valorem taxes. The fuel and other cost recovery revenues increased in 2011 compared to 2010 primarily as a result of higher recoverable fuel costs. Recoverable fuel costs include fuel and purchased power expenses reduced by the fuel portion of wholesale revenues from energy sold to customers outside the Company's service territory.

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 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 revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not have a significant impact on net income.

Wholesale revenues from sales to non-affiliates decreased $17.6 million, or 6.5%, in 2012 compared to 2011 as a result of a $31.0 million decrease in energy revenues, of which $23.2 million was associated with lower fuel prices and $7.8 million was associated with a decrease in kilowatt-hour (KWH) sales, partially offset by a wholesale base rate increase effective April 1, 2012. Wholesale revenues from sales to non-affiliates decreased $14.8 million, or 5.1%, in 2011 compared to 2010 as a result of a $13.4 million decrease in energy revenues, of which $11.4 million was associated with a decrease in KWH sales and $2.0 million was associated with lower fuel prices, and a $1.4 million decrease in capacity revenues resulting from the expiration of a power supply agreement in 2010, partially offset by a wholesale base rate increase effective January 2011.

Short-term opportunity energy sales are also included in sales for resale to non-affiliates. These opportunity sales are made at market-based rates that generally provide a margin above the Company's variable cost to produce the energy.

Wholesale revenues from sales to affiliated companies will vary from year to year depending on demand and the availability and cost of generating resources at each company. These affiliated 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.

Wholesale revenues from sales to affiliated companies decreased 46.1% in 2012 compared to 2011 primarily due to a $1.6 million decrease in capacity revenues and a $12.4 million decrease in energy revenues of which $9.1 million was associated with lower prices and $3.3 million was associated with a decrease in KWH sales. Wholesale revenues from sales to affiliated companies decreased 26.9% in 2011 compared to 2010 primarily due to a $2.5 million decrease in capacity revenues and an $8.7 million decrease in energy revenues of which $2.7 million was associated with lower prices and $6.0 million was associated with a decrease in KWH sales.

Other operating revenues in 2012 decreased $0.2 million, or 1.4%, from 2011 primarily due to a $1.0 million decrease in rent from electric property, partially offset by a $0.9 million increase in transmission revenues. Other operating revenues in 2011 increased $1.2 million, or 7.6%, from 2010 primarily due to a $1.8 million increase in transmission revenues.

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Mississippi Power Company 2012 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 2012 and percent change by year were as follows:

	Total KWHs 2012 (in millions)	Total KWH Percent Change 2012	Total KWH Percent Change 2011	Weather-Adjusted Percent Change 2012	Weather-Adjusted Percent Change 2011
Residential	2,046	(5.4)%	(5.8)%	2.3%	(0.4)%
Commercial	2,916	1.6	(1.8)	1.7	2.1
Industrial	4,702	2.5	2.7	2.5	2.7
Other	38	(0.2)	0.3	(0.2)	0.3
Total retail	9,702	0.5	(0.7)	2.2	1.8
Wholesale					
Non-affiliated	3,819	(4.8)	(6.4)		
Affiliated	572	(11.8)	(16.2)		
Total wholesale	4,391	(5.7)	(7.9)		
Total energy sales	14,093	(1.6)	(3.1)		

Changes in retail energy sales are comprised of changes in electricity usage by customers, changes in weather, and changes in the number of customers.
Residential energy sales decreased 5.4% in 2012 compared to 2011 due to milder weather, partially offset by a slight increase in the number of residential customers in 2012 compared to 2011. Residential energy sales decreased 5.8% in 2011 compared to 2010 due to closer to normal weather in 2011 compared to 2010 and a slight decline in the number of residential customers in 2011.
Commercial energy sales increased 1.6% in 2012 compared to 2011 due to increased economic activity in 2012 compared to 2011. Commercial energy sales decreased 1.8% in 2011 compared to 2010 due to closer to normal weather in 2011 compared to 2010.
Industrial energy sales increased 2.5% in 2012 compared to 2011 due to increased production for many of the industrial customers resulting from increased economic activity as well as expansions of some existing customers. Industrial energy sales increased 2.7% in 2011 compared to 2010 due to increased production for many of the industrial customers resulting from an improving economy as well as expansions of some existing customers.
Wholesale energy sales to non-affiliates decreased 4.8% in 2012 compared to 2011 primarily due to decreased KWH sales to rural electric cooperative associations and municipalities located in southeastern Mississippi resulting from milder weather in 2012 compared to 2011. KWH sales to non-affiliates decreased 6.4% in 2011 compared to 2010 primarily due to decreased KWH sales to rural electric cooperative associations and municipalities located in southeastern Mississippi resulting from closer to normal weather in 2011 compared to 2010.
Wholesale sales to non-affiliates will vary depending on fuel prices, the market prices of wholesale energy compared to the cost of the Company 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.
Wholesale energy sales to affiliates decreased 11.8% in 2012 compared to 2011 and 16.2% in 2011 compared to 2010 primarily due to a decrease in the Company's generation, resulting in less energy available to sell to affiliate 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)
Mississippi Power Company 2012 Annual Report

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

	2012	2011	2010
Total generation (millions of KWHs)	12,750	12,986	13,146
Total purchased power (millions of KWHs)	1,961	2,055	2,330
Sources of generation (percent) –			
Coal	26	40	51
Gas	74	60	49
Cost of fuel, generated (cents per net KWH) –			
Coal	5.09	4.39	4.08
Gas	2.90	3.88	4.22
Average cost of fuel, generated (cents per net KWH)	3.53	4.10	4.14
Average cost of purchased power (cents per net KWH)	2.81	3.49	3.59

Fuel and purchased power expenses were $466.4 million in 2012, a decrease of $95.9 million, or 17.1% below the prior year costs. The decrease was primarily due to a $70.5 million decrease in the cost of fuel and purchased power and a $25.4 million decrease related to lower total KWHs generated and purchased. Fuel and purchased power expenses were $562.2 million in 2011, a decrease of $23.3 million, or 4.0%, below the prior year costs. The decrease was primarily due to a $16.5 million decrease related to lower total KWHs generated and purchased and a $6.8 million decrease in the cost of fuel and purchased power.

From an overall global market perspective, coal prices decreased from levels experienced in 2011 due to lower demand. In the U.S., this decrease was due primarily to relatively lower domestic natural gas prices that contributed to displacement of coal generation by natural gas-fueled generating units. The share of natural gas power production for the Company was higher than the share of coal-fired production. Lower domestic natural gas prices in 2012 were driven by continued robust supplies, including production from shale gas, and only modest increases in overall U.S. consumption.

Fuel and purchased power energy transactions do not have a significant impact on earnings, since energy expenses are generally offset by energy revenues through the Company's fuel cost recovery clause. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" and Note 1 to the financial statements under "Fuel Costs" for additional information.

Fuel

Fuel expense decreased $79.2 million in 2012 compared to 2011. Approximately $66.2 million of the reduction in fuel expenses resulted primarily from lower fuel prices and a $13.0 million decrease in generation from Company-owned facilities. Fuel expense decreased $11.4 million in 2011 compared to 2010. Approximately $4.8 million of the reduction in fuel expenses resulted primarily from lower fuel prices and a $6.6 million decrease in generation from Company-owned facilities.

Purchased Power - Non-Affiliates

Purchased power expense from non-affiliates decreased $1.0 million, or 16.3%, in 2012 compared to 2011. The decrease was primarily the result of a 41.2% decrease in the average cost of purchased power per KWH, partially offset by a 42.3% increase in volume of KWHs purchased. The decrease in the average cost per KWH purchased was due to a lower marginal cost of fuel. The increase in the volume of KWHs purchased was due to a lower market cost of available energy compared to the cost of generation. Purchased power expense from non-affiliates decreased $2.2 million, or 26.0%, in 2011 compared to 2010. The decrease was primarily the result of a 32.4% decrease in the average cost of purchased power per KWH, partially offset by a 9.5% increase in volume of KWHs purchased.

Energy purchases from non-affiliates will vary depending on the market prices of wholesale energy 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 decreased $15.7 million, or 23.9%, in 2012 compared to 2011. The decrease was primarily the result of a 15.4% decrease in the average cost of purchased power per KWH and a 10.0% decrease in volume of KWHs purchased. Purchased power expense from affiliates decreased $9.7 million, or 12.8%, in 2011 compared to 2010. The decrease was primarily the result of a 13.7% decrease in volume of KWHs purchased, partially offset by a 1.0% increase in the average cost of purchased power per KWH.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Mississippi Power Company 2012 Annual Report

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, as approved by the FERC.

Other Operations and Maintenance Expenses

Other operations and maintenance expenses decreased $37.7 million in 2012 compared to 2011 primarily due to a $34.7 million decrease in rent expense and expenses under a long-term service agreement resulting from the expiration of the Plant Daniel Units 3 and 4 operating lease in October 2011 and a $6.3 million decrease in generation maintenance expenses for several major outages. These decreases were partially offset by a $2.8 million increase in administrative and general expenses. See FINANCIAL CONDITION AND LIQUIDITY – "Purchase of the Plant Daniel Combined Cycle Generating Units" herein for additional information.

Other operations and maintenance expenses decreased $1.7 million in 2011 compared to 2010 primarily due to a $4.0 million decrease in rent expense resulting from the expiration of the Plant Daniel Units 3 and 4 operating lease in October 2011 and a $4.6 million decrease in labor costs. These decreases were partially offset by a $4.2 million increase in generation maintenance expenses for several major outages, a $1.1 million increase in generation-related environmental expenses, and a $2.2 million increase in transmission and distribution expenses related to overhead line maintenance and vegetation maintenance costs.

Depreciation and Amortization

Depreciation and amortization increased $6.2 million in 2012 compared to 2011 primarily due to a $10.8 million increase in depreciation resulting from an increase in plant in service and a $6.2 million increase in amortization resulting from the plant acquisition adjustment related to the purchase of Plant Daniel Units 3 and 4, partially offset by a $4.5 million decrease in amortization resulting from a regulatory deferral associated with the purchase of Plant Daniel Units 3 and 4, a $3.3 million decrease in Environmental Compliance Overview (ECO) Plan amortization, and a $2.4 million decrease in amortization resulting from a regulatory deferral associated with operations and maintenance expenses that ended in 2011.

Depreciation and amortization increased $3.5 million in 2011 compared to 2010 primarily due to a $5.2 million increase in depreciation resulting from an increase in plant in service and a $1.5 million increase in amortization resulting from the plant acquisition adjustment related to the purchase of Plant Daniel Units 3 and 4, partially offset by a $2.5 million decrease in amortization resulting from a regulatory deferral associated with the purchase of Plant Daniel Units 3 and 4 and a $0.7 million decrease in ECO Plan amortization.

See Note 1 to the financial statements under "Depreciation and Amortization" and Note 3 to the financial statements under "Retail Regulatory Matters – Performance Evaluation Plan" and "Environmental Compliance Overview Plan" for additional information.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $9.3 million in 2012 compared to 2011 primarily as a result of an $11.7 million increase in ad valorem taxes resulting from the expiration of a tax exemption related to Plant Daniel Units 3 and 4, partially offset by a $2.2 million decrease in franchise taxes and a $0.2 million decrease in payroll taxes. Taxes other than income taxes increased $0.3 million in 2011 compared to 2010 primarily as a result of a $0.9 million increase in franchise taxes and a $0.3 million increase in payroll taxes, partially offset by a $0.9 million decrease in ad valorem taxes.

The retail portion of ad valorem taxes is recoverable under the Company's ad valorem tax cost recovery clause and, therefore, does not affect net income.

Allowance for Funds Used During Construction Equity

AFUDC equity increased $40.1 million in 2012 as compared to 2011 and $20.9 million in 2011 as compared to 2010. These increases were primarily due to increases in construction work in progress (CWIP) related to the construction of the Kemper IGCC which began in 2010. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information regarding the Kemper IGCC.

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Interest Expense, Net of Amounts Capitalized

Interest expense, net of amounts capitalized increased $19.1 million in 2012 compared to 2011, primarily due to a $39.0 million increase in interest expense associated with the issuances of new long-term debt in October 2011, March 2012, August 2012, and November 2012, and a $12.5 million increase in interest expense resulting from the receipt of a $150.0 million interest-bearing refundable deposit from South Mississippi Electric Power Association (SMEPA) in March 2012 related to its pending purchase of an undivided interest in the Kemper IGCC. These increases were partially offset by a $22.8 million increase in capitalized interest primarily resulting from AFUDC debt associated with the Kemper IGCC, a $6.1 million decrease in interest expense resulting from the amortization of the fair value adjustment in the assumed debt related to the purchase of Plant Daniel Units 3 and 4 in October 2011, and a $3.5 million decrease in interest expense associated with the redemption of long term debt in 2012.

Interest expense, net of amounts capitalized, decreased $0.7 million in 2011 compared to 2010 primarily due to a $5.3 million increase in capitalized AFUDC debt associated with the Kemper IGCC, a $1.9 million decrease in interest expense due to deferred interest on the regulatory assets related to Plant Daniel Units 3 and 4 of $1.4 million and the Kemper IGCC of $0.5 million, and a $1.5 million decrease in interest expense resulting from the amortization of the fair value adjustment in the assumed debt related to the purchase of Plant Daniel Units 3 and 4. These decreases were partially offset by a $7.9 million increase in interest expense associated with the issuances of new long-term debt in December 2010, April 2011, September 2011, and October 2011.

Other Income (Expense), Net

Other income (expense), net increased $0.5 million in 2012 compared to 2011 primarily due to a $1.6 million increase in the sale of property and a $1.1 million increase in non-operating income, partially offset by a $1.9 million increase in other deductions. Other income (expense), net decreased $3.8 million in 2011 compared to 2010 primarily due to a decrease in amounts collected from customers for contributions in aid of construction.

Income Taxes

Income taxes increased $8.2 million, or 19.4%, in 2012 compared to 2011 primarily resulting from higher pre-tax earnings and an increase due to lower State of Mississippi manufacturing investment tax credits, partially offset by an increase in AFUDC equity, which is non-taxable, and a decrease in unrecognized tax benefits. Income taxes decreased $4.1 million, or 8.8%, in 2011 compared to 2010 primarily due to an increase in AFUDC equity, which is non-taxable, and an increase in a State of Mississippi manufacturing investment tax credit, partially offset by increased pre-tax income.

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 in southeast Mississippi and to wholesale customers in the Southeast. Prices for electricity provided by the Company to retail customers are set by the Mississippi PSC under cost-based regulatory principles. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. Prices for wholesale electricity sales, interconnecting transmission lines, and the exchange of electric power are regulated by the FERC. See "FERC Matters" herein, ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – 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 construction of generating facilities. 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 neighboring 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

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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economic conditions impact sales for the Company, and 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

In 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including Alabama Power Company (Alabama Power) and Georgia Power Company (Georgia Power), alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. The EPA alleged NSR violations at five coal-fired generating facilities operated by Alabama Power, including a unit co-owned by the Company, and three coal-fired generating facilities operated by Georgia Power. The civil action sought penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. These actions were filed concurrently with the issuance of notices of violation to the Company with respect to the Company's Plant Watson. The case against Georgia Power was administratively closed in 2001 and has not been reopened. After Alabama Power was dismissed from the original action, the EPA filed a separate action in 2001 against Alabama Power (including claims related to the unit co-owned by the Company) in the U.S. District Court for the Northern District of Alabama.

In 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree, resolving claims relating to the alleged NSR violations at Plant Miller. In 2010, the EPA dismissed five of its eight remaining claims against Alabama Power, leaving only three claims, including one relating to the unit co-owned by the Company. In March 2011, the U.S. District Court for the Northern District of Alabama granted Alabama Power summary judgment on all remaining claims and dismissed the case with prejudice. That judgment is on appeal to the U.S. Court of Appeals for the Eleventh Circuit. On February 23, 2012, the EPA filed a motion in the U.S. District Court for the Northern District of Alabama seeking vacatur of the judgment and recusal of the judge in the case involving Alabama Power.

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.

Climate Change Litigation

Kivalina Case

In 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs allege that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that some of the defendants (including Southern Company) acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. In 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case. On September 21, 2012, the U.S. Court of Appeals for the Ninth Circuit upheld the U.S. District Court for the Northern District of California's dismissal of the case. On November 27, 2012, the U.S. Court of Appeals for the Ninth Circuit denied the plaintiffs' request for review of the decision. On February 25, 2013, the plaintiffs filed a petition for writ of certiorari with the U.S. Supreme Court. Southern Company believes that these claims are without merit. The ultimate outcome of this matter cannot be determined at this time.

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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 2012, the Company had invested approximately $300 million in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $52 million, $23 million, and $2 million for 2012, 2011, and 2010, respectively. The Company expects that base level capital expenditures to comply with existing statutes and regulations, including capital expenditures and compliance costs associated with the EPA's final Mercury and Air Toxics Standards (MATS) rule, will be a total of approximately $419 million from 2013 through 2015, with annual totals of approximately $129 million, $174 million, and $116 million for 2013, 2014, and 2015, respectively.

The Company continues to monitor the development of the EPA's proposed water and coal combustion byproducts 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 byproducts rules for 2013 through 2015. The ultimate capital expenditures and compliance costs with respect to these proposed rules, including additional expenditures required after 2015, 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 Byproducts" 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, and adding or changing fuel sources for certain existing units. The ultimate outcome of these matters cannot be determined at this time.

Compliance with any new federal or state legislation or regulations relating to air quality, water, coal combustion byproducts, 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 $183 million 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.

Final revisions to the National Ambient Air Quality Standard for sulfur dioxide (SO_2), including the establishment of a new one-hour standard, became effective in 2010. The EPA plans to issue area designations under this new standard in June 2013, and areas within the Company's service territory could ultimately be designated as nonattainment. Implementation of the revised SO_2 standard could require additional reductions in SO_2 emissions and increased compliance and operational costs.

Revisions to the National Ambient Air Quality Standard for nitrogen dioxide (NO_2), which established a new one-hour standard, became effective in 2010. On February 29, 2012, the new NO_2 standard became effective. The EPA designated the entire country as "unclassifiable/attainment" under the new standard, with no nonattainment areas designated. However, the new NO_2 standard could result in significant additional compliance and operational costs for units that require new source permitting.

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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 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 August 2011, the EPA adopted the Cross State Air Pollution Rule (CSAPR) to replace CAIR effective January 1, 2012. However, in December 2011, the U.S. Court of Appeals for the District of Columbia Circuit stayed the rule and, on August 21, 2012, vacated CSAPR in its entirety and directed the EPA to continue to administer CAIR pending the EPA's development of a valid replacement. On January 24, 2013, the U.S. Court of Appeals for the District of Columbia Circuit denied requests by the EPA and other parties for rehearing.

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 (BART) 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 2005, the EPA determined that compliance with CAIR satisfies BART obligations under CAVR, but on June 7, 2012, the EPA issued a final rule replacing CAIR with CSAPR as an alternative means of satisfying BART obligations. The vacatur of CSAPR creates additional uncertainty with respect to whether additional controls may be required for CAVR and BART compliance.

On February 16, 2012, the EPA published the final 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, unless a one-year compliance extension is granted by the state or local air permitting agency. The Company has received this one-year compliance extension for Plant Daniel to April 16, 2016.

Numerous petitions for administrative reconsideration of the MATS rule, including a petition by the Company, have been filed with the EPA. On November 30, 2012, the EPA proposed a reconsideration of certain new source and startup/shutdown issues. The EPA plans to complete its reconsideration rulemaking by March 2013. Challenges to the final rule have also been filed in the U.S. District Court for the District of Columbia by numerous states, environmental organizations, industry groups, and others.

On August 29, 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 Alabama and Mississippi) 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. If finalized as proposed, this new requirement could result in significant additional compliance and operational costs.

The Company has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the existing and new environmental requirements discussed above. The impacts of the eight-hour ozone, SO_2 and NO_2 standards, 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.
See Note 3 to the financial statements under "Retail Regulatory Matters – Environmental Compliance Overview Plan" for additional information.
Water Quality
In April 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 has entered into an amended settlement agreement to

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extend the deadline for issuing a final rule until June 27, 2013. If finalized as proposed, some of the Company's facilities may be subject to 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. The ultimate outcome of this rulemaking will depend on the final rule and the outcome of any legal challenges and cannot be determined at this time.

The EPA has announced its determination that revision of the current effluent guidelines for steam electric power plants is warranted and has stated that it intends to propose such revisions by April 2013 and finalize the revisions by May 2014. New advanced wastewater treatment requirements are expected and may result in the installation of additional controls on certain of the Company's facilities, which could result in significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. The impact of the revised guidelines will depend on the specific technology requirements of the final rule and, therefore, cannot be determined at this time. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" for additional information regarding estimated compliance costs for 2013 through 2015.

Coal Combustion Byproducts

The Company currently operates two electric generating plants with on-site coal combustion byproducts storage facilities. In addition to on-site storage, the Company also sells a portion of its coal combustion byproducts to third parties for beneficial reuse. Historically, individual states have regulated coal combustion byproducts and the States of Mississippi and Alabama each has its own regulatory parameters. 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 byproducts, 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 byproducts: 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 byproducts 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 byproducts.

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 byproducts could have a material impact on the generation, management, beneficial use, and disposal of such byproducts. 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. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" for additional information regarding estimated compliance costs for 2013 through 2015.

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 has authority from the Mississippi PSC to recover approved environmental compliance costs through its ECO clause. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Note 3 to the financial statements under "Environmental Matters – Environmental Remediation" for additional information.

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Global Climate Issues

The EPA currently regulates greenhouse gases under the Prevention of Significant Deterioration and Title V operating permit programs of the Clean Air Act. 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 April 13, 2012, the EPA published proposed regulations to establish standards of performance for greenhouse gas emissions from new fossil fuel steam electric generating units. The EPA has also announced plans to develop federal guidelines for states to establish greenhouse gas emissions performance standards for existing sources. The impact of this rulemaking will depend on the scope and specific requirements of the final rule and the outcome of any legal challenges and, therefore, cannot be determined at this time.

Although the outcome of federal, state, and international initiatives 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 a significant number 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 reported 2011 greenhouse gas emissions of approximately 9 million metric tons of carbon dioxide equivalent. The preliminary estimate of the Company's 2012 greenhouse gas emissions on the same basis is approximately 7 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, which is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units.

FERC Matters

In November 2011, the Company filed a request with the FERC for an increase in wholesale base revenues of approximately $32 million under the wholesale cost-based electric tariff. In its filing with the FERC, the Company sought (i) approval to establish a regulatory asset for the portion of non-capitalizable Kemper IGCC-related costs which have been and will continue to be incurred during the construction period for the Kemper IGCC, (ii) authorization to defer as a regulatory asset, for the 10-year period ending October 2021, the difference between the revenue requirement under the purchase option of Plant Daniel Units 3 and 4 (assuming a remaining 30-year life) and the revenue requirement assuming the continuation of the operating lease regulatory treatment with the accumulated deferred balance at the end of the deferral being amortized into wholesale rates over the remaining life of Plant Daniel Units 3 and 4, and (iii) authority to defer in a regulatory asset costs related to the retirement or partial retirement of generating units as a result of environmental compliance rules.

On March 9, 2012, the Company entered into a settlement agreement with its wholesale customers with respect to the Company's request for revised rates under the wholesale cost-based electric tariff. The settlement agreement provides that base rates under the cost-based electric tariff will increase by approximately $22.6 million over a 12-month period with revised rates effective April 1, 2012. A significant portion of the difference between the requested base rate increase and the agreed upon rate increase is due to a change in the CWIP recovery on the Kemper IGCC. Under the settlement agreement, a portion of CWIP will continue to accrue AFUDC. The tariff customers specifically agreed to the same regulatory treatment for tariff ratemaking as the treatment approved for retail ratemaking by the Mississippi PSC with respect to (i) the accounting for Kemper IGCC-related costs that cannot be capitalized, (ii) the accounting for the lease termination and purchase of Plant Daniel Units 3 and 4, and (iii) the establishment of a regulatory asset

for certain potential plant retirement costs.
On March 28, 2012, the FERC approved a motion to place interim rates into effect beginning in May 2012. On September 27, 2012, the Company, with its wholesale customers, filed a final settlement agreement with the FERC. On November 5, 2012, the settlement judge certified the settlement agreement to the FERC with the recommendation that it be approved. The FERC has not yet approved the settlement agreement. The ultimate outcome of this matter cannot be determined at this time.

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PSC Matters
General
On August 7, 2012, the Mississippi PSC issued an order for the purpose of investigating and reviewing for informational purposes only the ROE formulas used by the Company and all other regulated electric utilities in Mississippi. The ultimate outcome of this matter cannot be determined at this time.
Performance Evaluation Plan
In the 2004 order establishing the Company's forward-looking PEP, the Mississippi PSC ordered that the Mississippi Public Utilities Staff (MPUS) and the Company review the operations of the PEP in 2007. By mutual agreement, this review was deferred until 2008 and continued into 2009. In 2009, concurrent with this review, the annual PEP evaluation filing for 2009 was suspended and the MPUS and the Company filed a joint report with the Mississippi PSC proposing several changes to the PEP. The Mississippi PSC approved the revised PEP in 2009, which resulted in a lower performance incentive under the PEP and therefore smaller and/or less frequent rate changes in the future. Later that year, the Company resumed annual evaluations and filed its annual PEP filing for 2010 under the revised PEP, which resulted in a lower allowed return on investment but no rate change.
In 2010, the Company filed its annual PEP filing for 2011 under the revised PEP, which indicated a rate increase of 1.936%, or $16.1 million, annually. In January 2011, the MPUS contested the filing. In June 2011, the Mississippi PSC issued an order approving a joint stipulation between the MPUS and the Company resulting in no change in rates.
In November 2011, the Company filed its annual PEP filing for 2012, which indicated a rate increase of 1.893%, or $17.4 million, annually. On January 10, 2012, the MPUS contested the filing.
In March 2011, the Company submitted its annual PEP lookback filing for 2010, which recommended no surcharge or refund. In May 2011, the Company received a letter from the MPUS disputing certain items in the 2010 PEP lookback filing. On April 2, 2012, the Company filed a motion to suspend the PEP lookback filing for 2011. Unresolved matters related to certain costs included in the 2010 PEP lookback filing also impact the 2011 PEP lookback filing, making it impractical to determine the Company's actual retail return on investment for 2011 for purposes of the 2011 PEP lookback filing. An order granting the suspension of the 2011 PEP lookback was signed by the Mississippi PSC on May 8, 2012. On or before March 15, 2013, the Company will submit its annual PEP lookback filing for 2012. While the Company does not expect the resolution of these unresolved matters to have a material impact on its financial statements, the ultimate outcome of these matters cannot be determined at this time.
On January 18, 2013, the Company filed its annual PEP filing for 2013, which indicated a rate increase of 1.990%, or $15.8 million, annually.
The ultimate outcome of these matters cannot be determined at this time.
Environmental Compliance Overview Plan
In November 2011, the Company filed a request to establish a regulatory asset to defer certain plant retirement costs if such costs are incurred. This request was made to minimize the potential rate impact to customers arising from pending and final environmental regulations which may require the premature retirement of some generating units. These environmental rules and regulations are continuously being monitored by the Company and all options are being evaluated. In December 2011, an order was issued by the Mississippi PSC authorizing the Company to defer all plant retirement related costs resulting from compliance with environmental regulations as a regulatory asset for future recovery.
On February 14, 2012, the Company submitted its 2012 ECO Plan filing, which proposed a 0.3% increase in annual revenues for the Company. In compliance with the CPCN to construct a flue gas desulfurization system (scrubber) on Plant Daniel Units 1 and 2, the Company revised the 2012 ECO Plan filing to exclude scrubber expenditures from rate base, which resulted in a 0.16% decrease in annual revenues. On June 22, 2012, the 2012 ECO Plan filing, including the proposed rate decrease, was approved by the Mississippi PSC, effective on June 29, 2012.
On April 3, 2012, the Mississippi PSC approved the Company's request for a CPCN to construct a scrubber on Plant Daniel Units 1 and 2. On May 3, 2012, the Sierra Club filed a notice of appeal of the order with the Chancery Court of

Harrison County, Mississippi (Chancery Court). These units are jointly owned by the Company and Gulf Power, with 50% ownership each. The estimated total cost of the project is approximately $660 million, with the Company's portion being $330 million, excluding AFUDC. The project is scheduled for completion in December 2015. The Company's portion of the cost is expected to be recovered through the ECO Plan. As of December 31, 2012, total project expenditures were $146.6 million, with the Company's portion being $73.3 million.

On February 12, 2013, the Company submitted its 2013 ECO Plan filing, which proposed no change in rates.

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

Certificated New Plant

See "Integrated Coal Gasification Combined Cycle" for information on certificated new plant and the Company's cost recovery plans.

Fuel Cost Recovery

The Company establishes, annually, a retail fuel cost recovery factor that is approved by the Mississippi PSC. On January 18, 2013, in compliance with the Company's filing requirement, the Company requested an annual adjustment of the retail fuel cost recovery factor in an amount equal to a decrease of 4.7% of total 2012 retail revenue. At December 31, 2012, the amount of over recovered retail fuel costs included in the balance sheets was $56.6 million compared to $42.4 million at December 31, 2011. The Company also has a wholesale Municipal and Rural Associations (MRA) and a Market Based (MB) fuel cost recovery factor. Effective January 1, 2013, the wholesale MRA fuel rate decreased resulting in an annual decrease in an amount equal to 3.3% of total 2012 MRA revenue. Effective February 1, 2013, the wholesale MB fuel rate decreased, resulting in an annual decrease in an amount equal to 5.5% of total 2012 MB revenue. At December 31, 2012, the amount of over recovered wholesale MRA and MB fuel costs included in the balance sheets was $19.0 million and $2.1 million compared to $14.3 million and $2.2 million, respectively, at December 31, 2011. In addition, at December 31, 2012, the amount of over recovered MRA emissions allowance cost included in the balance sheets was $0.4 million compared to $1.7 million at December 31, 2011. The Company's operating revenues are adjusted for differences in actual recoverable fuel cost and amounts billed in accordance with the currently approved cost recovery rate. Accordingly, changes in the billing factor have no significant effect on the Company's revenues or net income, but will affect annual cash flow.

In March 2011, a portion of the Company's territorial wholesale loads that was formerly served under the MB tariff terminated service. Beginning in April 2011, a new power purchase agreement (PPA) went into effect to cover these MB customers as non-territorial load. In June 2011, the Company and SMEPA reached an agreement to allocate $3.7 million of the over recovered fuel balance at March 31, 2011 to the PPA. This amount was subsequently refunded to SMEPA in June 2011. See "Other Matters" herein for additional information.

The Mississippi PSC engaged an independent professional audit firm to conduct an audit of the Company's fuel-related expenditures included in the retail fuel adjustment clause and energy cost management clause (ECM). The 2012 audit of fuel-related expenditures began in the second quarter 2012 and was completed in the fourth quarter 2012 with no audit findings.

Storm Damage Cost Recovery

In August 2012, Hurricane Isaac hit the Gulf Coast of the United States and caused damage within the Company's service area. The estimated total storm restoration costs relating to Hurricane Isaac through December 31, 2012 were $10.5 million. The Company maintains a reserve to cover the cost of damage from major storms to its transmission and distribution facilities and generally the cost of uninsured damage to its generation facilities and other property. At December 31, 2012, the balance in the storm reserve was $58.8 million.

Income Tax Matters

Bonus Depreciation

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 to be placed in service in 2013), which will have a positive impact on the future cash flows of the Company through 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 to be 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 scheduled to be placed in service in May 2014.

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Due to the significant amount of estimated bonus depreciation for 2013, the utilization of a portion of the Company's tax credits has been delayed. See "Integrated Coal Gasification Combined Cycle – Tax Incentives" for additional information.

Integrated Coal Gasification Combined Cycle

General

The Company is constructing the Kemper IGCC which will utilize an IGCC technology with an output capacity of 582 MWs. The Kemper IGCC will use as fuel locally mined lignite (an abundant, lower heating value coal) from a mine owned by the Company and situated adjacent to the Kemper IGCC. In connection with the Kemper IGCC, the Company also plans to construct and operate approximately 61 miles of carbon dioxide (CO_2) pipeline infrastructure. The Kemper IGCC is scheduled to be placed in-service in May 2014.

In 2010, the Mississippi PSC issued a CPCN authorizing the acquisition, construction, and operation of the Kemper IGCC (2010 MPSC Order). The Sierra Club filed an appeal of the Mississippi PSC's issuance of the CPCN and, on March 15, 2012, the Mississippi Supreme Court reversed the decision of the Chancery Court of Harrison County Mississippi (Chancery Court) upholding the 2010 MPSC Order and remanded the matter to the Mississippi PSC. The Mississippi Supreme Court concluded that the 2010 MPSC Order did not cite in sufficient detail substantial evidence upon which the Mississippi Supreme Court could determine the basis for the findings of the Mississippi PSC granting the CPCN. On March 30, 2012, the Mississippi PSC issued a temporary authorization which allowed the Company to continue construction and, on April 24, 2012, issued a detailed order (2012 MPSC Order) confirming the CPCN for the Kemper IGCC. On April 26, 2012, the Sierra Club appealed the 2012 MPSC Order to the Chancery Court. On December 17, 2012, the Chancery Court affirmed the 2012 MPSC Order which confirmed the issuance of the CPCN for the Kemper IGCC. On January 8, 2013, the Sierra Club filed an appeal of the Chancery Court's ruling with the Mississippi Supreme Court.

The certificated cost estimate of the Kemper IGCC included in the 2012 MPSC Order was $2.4 billion, net of $245.3 million of grants awarded to the project by the United States Department of Energy (DOE) under the Clean Coal Power Initiative Round 2 (CCPI2) and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, and financing costs related to the Kemper IGCC. The 2012 MPSC 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. Exemptions from the cost cap included in the 2012 MPSC Order included the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, financing costs, and certain general exceptions, including change of law, force majeure, and beneficial capital (which exists when the Company 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).

The Company's current cost estimate for the Kemper IGCC (net of the $245.3 million CCPI2 grant, and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, financing costs, and certain general exceptions as contemplated in the 2012 MPSC Order and the Settlement Agreement that must be specifically approved by the Mississippi PSC) is approximately $2.88 billion. The Mississippi PSC and the MPUS have engaged their independent monitors to assess the current cost estimates and schedule projections for the Kemper IGCC. These consultants have issued reports with their own opinions as to the likelihood that costs for the Kemper IGCC will remain at or under the $2.88 billion cost cap and as to the expected in-service date. While the Company continues to believe its cost estimate and schedule projection remain appropriate based on the current status of the project, it is possible that the Company could experience further cost increases and/or schedule delays with respect to the Kemper IGCC. Certain factors have caused and may continue to cause the costs for the Kemper IGCC to increase and/or schedule delays to occur including, but not limited to, costs and productivity of labor, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay or non-performance under construction or other agreements, and unforeseen engineering problems. To the extent it becomes probable that costs beyond any permitted exceptions to the cost cap will exceed $2.88 billion or it becomes probable that the

Mississippi PSC will disallow a portion of the costs relating to the Kemper IGCC, including certain general exceptions as contemplated in the 2012 MPSC Order and the Settlement Agreement, charges to expense may occur and these charges could be material. See "Cost Recovery Plans" below for additional information relating to the Settlement Agreement that defines the process for resolving matters regarding cost recovery related to the Kemper IGCC.

As of December 31, 2012, the Company had spent a total of $2.51 billion on the Kemper IGCC, including the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, and other deferred costs. Of this total, $2.47 billion was included in CWIP (which is net of $245.3 million of CCPI2 grant funds), $34.9 million was recorded in other regulatory assets, $3.8 million was recorded in other deferred charges and assets, and $1.0 million was previously expensed. Consistent with the treatment of non-capital costs incurred during the pre-construction period, the Mississippi PSC granted the Company the authority to defer all non-capital Kemper IGCC-related costs to a regulatory asset during the construction period. This includes deferred costs associated with the generation resource planning, evaluation, and screening activities. The amortization period for the regulatory asset will be determined by the Mississippi PSC at a later date.

In addition, the Company 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.

The 2012 MPSC Order established periodic prudence reviews during the annual CWIP review process. Of the total costs of $51 million incurred through March 2009, $46 million has been reviewed and deemed prudent by the Mississippi PSC. Due to the decision of the Mississippi PSC to deny the CNP-A rate filing and a 2012 rate request related to the Kemper IGCC described below, prudence reviews for the construction costs of the Kemper IGCC incurred after March 2009 have not been made. The Settlement Agreement provides for completion of all prudence reviews within six months of the date the Kemper IGCC is placed in service. See "Cost Recovery Plans" herein for additional information.

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

Cost Recovery Plans

The 2012 MPSC Order included provisions relating to both the Company's recovery of financing costs during the course of construction of the Kemper IGCC and the Company's recovery of costs following the date the Kemper IGCC is placed in service. In the 2012 MPSC Order, the Mississippi PSC approved financing cost recovery on CWIP balances not to exceed the $2.4 billion certificated cost estimate for the Kemper IGCC. The 2012 MPSC Order provided for the accrual of AFUDC in 2010 and 2011 and for the current recovery of financing costs on 100% of CWIP in 2012, 2013, and through May 1, 2014 (provided that the amount of financing cost recovery allowed is to be reduced by the amount of certain state and federal government construction cost incentives received by the Company and must be justified by a showing that such recovery will benefit customers over the life of the Kemper IGCC). With respect to recovery of costs following the in-service date of the Kemper IGCC, the 2012 MPSC Order provided for the establishment of operational cost and revenue parameters based upon assumptions in the Company's petition for the CPCN.

On June 1, 2012, the MPUS signed a joint stipulation with the Company to establish a proposed rate schedule detailing CNP-A and, on June 14, 2012, the Company submitted to the Mississippi PSC a filing to establish the new CNP-A rate schedule and a stipulated rate increase based upon the revenue request of between $55.3 million and $58.6 million to recover financing costs over the remainder of 2012. On June 22, 2012, the Mississippi PSC denied the proposed CNP-A rate schedule and the 2012 rate recovery filings submitted by the Company, 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.

On July 9, 2012, the Company appealed the Mississippi PSC's June 22, 2012 decision to the Mississippi Supreme Court and requested interim rates under bond of $55.3 million. On July 31, 2012, the Mississippi Supreme Court denied the Company's request for interim rates under bond until the Mississippi Supreme Court decides the Company's appeal of the Mississippi PSC's June 22, 2012 decision.

On January 24, 2013, the Company and the Mississippi PSC entered into the Settlement Agreement that (1) establishes the process for resolving matters regarding cost recovery related to the Kemper IGCC for the purpose of mitigating risks to the Company and its customers and expediting the regulatory process associated with future rate filings required under the Settlement Agreement and (2) resolves the Company's CNP-A rate appeal before the Mississippi Supreme Court.

On February 12, 2013, the Mississippi Supreme Court granted the Company and the Mississippi PSC's joint filing for dismissal of the Company's appeal of the Mississippi PSC's June 22, 2012 decision.

Under the terms of the Settlement Agreement, the Company and the Mississippi PSC will follow certain agreed-upon regulatory procedures and schedules for resolving the cost recovery matters related to the Kemper IGCC. These procedures and schedules include the following: (1) the Company's filing within 30 days of the Settlement Agreement of a new request to increase rates in 2013 in an amount not to exceed a $172 million annual revenue requirement, based upon projected investment as of December 31, 2013, to be recorded to a regulatory liability to be used to mitigate rate impacts when the Kemper IGCC is placed in service (which filing for $172 million was made on January 25, 2013); (2) the Mississippi PSC's decision on that matter within 50 days of the Company's request; (3) the Company's collaboration with the MPUS to file with the Mississippi PSC within three months of the Settlement Agreement 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 (which filing was made on February 26, 2013 as described below); (4) the Mississippi PSC's decision on the rate recovery plan within four months of that filing; (5) the Company's agreement to limit the portion of prudently-incurred Kemper IGCC costs to be included in rate base to the $2.4 billion certificated

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cost estimate, plus costs related to the lignite mine and CO_2 pipeline as well as any other costs permitted or determined to be excluded from the cost cap, provided that this limitation will not prevent the Company from securing alternate financing to recover any prudently-incurred Kemper IGCC costs, including financing costs and plant costs above the $2.4 billion certificated cost estimate, not otherwise recovered in any Mississippi PSC rate proceeding contemplated by the Settlement Agreement; and (6) the Mississippi PSC's completion of its prudence review of the Kemper IGCC costs incurred through 2012 within six months of the Settlement Agreement, an additional prudence review upon considering the seven-year rate plan for costs incurred through the most recent reporting period, and a final prudence review of the remaining project costs within six months of the Kemper IGCC's in-service date.
Legislation to authorize a multi-year rate plan and legislation to provide for alternate financing through securitization was passed in the Mississippi legislature and was signed by the Governor on February 26, 2013. The Company contemplates using securitization as provided in the legislation as its form of alternate financing for prudently-incurred Kemper IGCC costs, including financing costs and plant costs above the $2.4 billion certificated cost estimate, not otherwise recovered in any Mississippi PSC rate proceeding contemplated by the Settlement Agreement.
On February 26, 2013, the Company, in compliance with the Settlement Agreement, filed with the Mississippi PSC a rate recovery plan for the Kemper IGCC for 2014 through 2020, the first seven years of operation of the Kemper IGCC. The rate recovery plan proposes recovery of an annual revenue requirement of approximately $150 million of Kemper IGCC-related operational costs and rate base amounts, including plant costs equal to the $2.4 billion certificated cost estimate. Approval of the Company's request to increase rates in 2013 to mitigate the rate impacts of the Kemper IGCC filed on January 25, 2013 is integral to the rate recovery plan as the proposed filing contemplates amortization of the regulatory liability to be used to mitigate rate impacts from 2014 through 2020, based on a fixed amortization schedule that requires approval by the Mississippi PSC. Under the rate recovery plan filing, the Company proposes annual recovery to remain the same from 2014 through 2020 and while it is the intent of the Company for the actual revenue requirement to equal the proposed revenue requirement for certain items, the Company proposes that the annual differences for those items through 2020 will be deferred, subject to accrual of carrying costs, and the cumulative balance will be reviewed at the end of the term of the Settlement Agreement by the Mississippi PSC for determination of the manner of recovery. The Company proposes to secure recovery of prudently-incurred Kemper IGCC costs, including financing costs and plant costs above the $2.4 billion certificated cost estimate, not otherwise recovered in any Mississippi PSC rate proceeding contemplated by the Settlement Agreement to be provided for with alternate financing through securitization. The rate recovery necessary to recover the annual costs of securitization is proposed to be filed and begin after the Kemper IGCC is placed in service.
Under the terms of the Settlement Agreement, the Company has the right to terminate the Settlement Agreement if certain conditions, including the passage of multi-year rate plan legislation that is contemplated under the Settlement Agreement, are not met, if the Company 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.
The ultimate outcome of these matters, including the determinations of prudency and the specific manner of recovery of prudently-incurred costs relating to the Kemper IGCC, is subject to further regulatory actions and cannot be determined at this time.

Tax Incentives

The Internal Revenue Service (IRS) has allocated $133 million (Phase I) and $279 million (Phase II) of Internal Revenue Code Section 48A tax credits to the Company in connection with the Kemper IGCC. The Company's utilization of Phase I and Phase II credits is dependent upon meeting the IRS certification requirements, including an in-service date no later than May 11, 2014 for the Phase I credits and April 19, 2016 for the Phase II credits. In order to remain eligible for the Phase II credits, the Company plans to capture and sequester (via enhanced oil recovery) at least 65% of the CO_2 produced by the Kemper IGCC during operations in accordance with the rules for Section 48A investment tax credits. Through December 31, 2012, the Company received or accrued tax benefits totaling $361.6 million for these tax credits, which will be amortized as a reduction to depreciation and amortization over the life of the Kemper IGCC. As a result of bonus tax depreciation on certain assets placed, or to be placed, in service in 2012 and 2013, and the subsequent reduction in federal taxable income, the Company estimates that it will not be able to utilize $170.9 million of these tax credits until after 2013. IRS guidelines allow these unused tax credits to be carried forward for 20 years, expiring at the end of 2031, if not utilized before then. On October 15, 2012, the Company filed an application with the DOE for certification of the Kemper IGCC for additional tax credits under the Internal Revenue Code Section 48A (Phase III). A portion of the tax credits realized by the Company may be subject to recapture upon successful completion of SMEPA's purchase of an undivided interest in the Kemper IGCC as described below. In addition, all or a portion of the tax credits will be subject to recapture if the Company fails to satisfy the in-service date requirements and carbon capture requirements described above. See "Income Tax Matters" herein for additional information.

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

Lignite Mine and CO_2 Pipeline Facilities

In conjunction with the Kemper IGCC, the Company will own the 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 is scheduled to be placed in-service in June 2013. The estimated capital cost of the mine is approximately $245 million, of which $163.3 million has been incurred through December 31, 2012.

In 2010, the Company 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 the Company has a contractual obligation to fund all reclamation activities. In addition to the obligation to fund the reclamation activities, the Company currently provides working capital support to Liberty Fuels through cash advances for capital purchases, payroll, and other operating expenses.

In addition, the Company will acquire, construct, and operate the CO_2 pipeline for the planned transport of captured CO_2 for use in enhanced oil recovery. The Company 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 estimated capital cost of the CO_2 pipeline facilities is approximately $132 million, of which $78.4 million has been incurred through December 31, 2012.

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

Proposed Sale of Undivided Interest to SMEPA

In 2010, the Company and SMEPA entered into an asset purchase agreement whereby SMEPA agreed to purchase a 17.5% undivided interest in the Kemper IGCC. On February 28, 2012, the Mississippi PSC approved the sale and transfer of 17.5% of the Kemper IGCC to SMEPA. On June 29, 2012, the Company and SMEPA signed an amendment to the asset purchase agreement whereby SMEPA extended its option to purchase until December 31, 2012 and 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 December 31, 2012, the Company and SMEPA agreed to extend SMEPA's option to purchase through December 31, 2013.

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. On September 27, 2012, SMEPA received a conditional loan commitment from Rural Utilities Service to provide funding for SMEPA's undivided interest in the Kemper IGCC.

On March 6, 2012, the Company received a $150 million interest-bearing refundable deposit from SMEPA to be applied to the purchase. While the expectation is that the amount will be applied to the purchase price at closing, the Company would be required to refund the deposit 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 the Company 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 Services, Inc. (Moody's) or ceases to be rated by either of these rating agencies.

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

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

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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 will depend on the outcome of any legal challenges and cannot be determined at this time. See "Cost Recovery Plans" herein for additional information regarding certain legislation related to the Kemper IGCC.

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 CO_2 and other emissions, coal combustion byproducts, 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.

On February 6, 2013, the Company submitted a claim under the Deepwater Horizon Economic and Property Damages Settlement Agreement associated with the oil spill that occurred in April 2010 in the Gulf of Mexico. 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 Mississippi PSC and wholesale regulation by the FERC. These regulatory agencies set the rates the Company is permitted to charge customers based on allowable costs. As a result, the Company applies accounting standards which require the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of the accounting standards has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the Company; therefore, the accounting estimates inherent in specific costs such as depreciation and pension and postretirement benefits have less of a direct impact on the Company's results of operations and financial condition than they would on a non-regulated company.

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

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Contingent Obligations
The Company is subject to a number of federal and state laws and regulations, as well as other factors and conditions that subject it to environmental, litigation, income tax, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. The Company periodically evaluates its exposure to such risks and, in accordance with GAAP, records reserves for those matters where a non-tax-related loss is considered probable and reasonably estimable and records a tax asset or liability if it is more likely than not that a tax position will be sustained. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect the Company's financial statements.
Unbilled Revenues
Revenues related to the retail sale of electricity are recorded when electricity is delivered to customers. However, the determination of KWH sales to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, amounts of electricity delivered to customers, but not yet metered and billed, are estimated. Components of the unbilled revenue estimates include total KWH territorial supply, total KWH billed, estimated total electricity lost in delivery, and customer usage. These components can fluctuate as a result of a number of factors including weather, generation patterns, power delivery volume, and other operational constraints. These factors can be unpredictable and can vary from historical trends. As a result, the overall estimate of unbilled revenues could be significantly affected, which could have a material impact on the Company's results of operations.
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 $1.5 million or less change in total annual benefit expense and an $18.4 million or less change in projected obligations.
Allowance for Funds Used During Construction
In accordance with regulatory treatment, the Company records AFUDC, which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently from such allowance, AFUDC increases the revenue requirement over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in the

calculation of taxable income. The average annual AFUDC rate was 7.04%, 7.06%, and 7.33% for the years ended December 31, 2012, 2011, and 2010, respectively. The AFUDC rate is applied to CWIP consistent with jurisdictional regulatory treatment. AFUDC, net of income taxes, as a percentage of net income after dividends on preferred stock was 57.05%, 31.60%, and 6.97% for 2012, 2011, and 2010, respectively.

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FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2012. 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 2013 through 2015, 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, 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 increased in value as of December 31, 2012 as compared to December 31, 2011. In December 2012, the Company contributed $43.0 million to the qualified pension plan.

Net cash provided from operating activities totaled $235.4 million for 2012, an increase of $3.9 million as compared to the corresponding period in 2011. The increase in net cash provided from operating activities was primarily due to an increase in investment tax credits received related to the Kemper IGCC and an increase in over recovered regulatory clause revenues. The increase in cash provided from operating activities was partially offset by a contribution to the qualified pension plan in 2012, payments for fuel stock, and the settlement of interest rate swaps. Net cash provided from operating activities in 2011 totaled $231.5 million, an increase of $98.8 million compared to 2010. The increase in net cash provided from operating activities was primarily due to a decrease in the use of funds related to the Kemper IGCC generation construction screening costs incurred during 2010, cash payment made in 2010 to fund the qualified pension plan, and a decrease in prepaid income taxes. These increases in cash provided from operating activities were partially offset by a decrease in over recovered regulatory clause revenues and a decrease in fossil fuel stock.

Net cash used for investing activities totaled $1.5 billion for 2012 primarily due to an increase in property additions primarily related to the Kemper IGCC, partially offset by a decrease in restricted cash, a decrease in capital grant proceeds received primarily related to CCPI2 and Smart Grid Investment grants, and a decrease in plant acquisition due to the cash payment associated with the purchase of Plant Daniel Units 3 and 4 in 2011. Net cash used for investing activities in 2011 totaled $682.7 million primarily due to an increase in property additions primarily related to the Kemper IGCC and an increase in plant acquisition due to the cash payment associated with the purchase of Plant Daniel Units 3 and 4. These increases in cash used for investing activities were partially offset by an increase in construction payables, a change in restricted cash associated with the second series revenue bonds issued in 2010, and an increase in capital grant proceeds received primarily related to CCPI2 and Smart Grid Investment grants.

Net cash provided from financing activities totaled $1.2 billion in 2012 primarily due to an increase in capital contributions from Southern Company, an increase in long-term debt financings and the receipt of an interest bearing refundable deposit related to a pending asset sale, partially offset by redemptions of long-term debt financings. Net cash provided from financing activities totaled $502.0 million in 2011 primarily due to an increase in capital contributions from Southern Company, an increase in long-term debt, and redemptions of long-term debt financings.

Significant changes in the balance sheet as of December 31, 2012 compared to 2011 include an increase in prepaid income taxes of $92.0 million and an increase in accumulated deferred investment tax credits of $260.8 million primarily due to the Kemper IGCC investment tax credit. Total property, plant, and equipment increased $1.6 billion primarily due to the increase in CWIP related to the Kemper IGCC. Interest-bearing refundable deposit related to an asset sale increased $150.0 million due to the receipt of the $150.0 million interest-bearing refundable deposit from SMEPA. Long-term debt increased $460.9 million primarily due to the issuance of $600.0 million of senior notes, partially offset by the redemption of $90.0 million of senior notes and the reclassification of a $50.0 million long-term bank loan maturing in November 2013. Common stockholder's equity increased $748.2 million primarily due to the increase in paid-in capital due to $700.0 million in capital contributions from Southern Company in 2012.

The Company's ratio of common equity to total capitalization, excluding long-term debt due within one year, increased from 48.0% in 2011 to 52.9% at December 31, 2012.

Sources of Capital

Except as described herein, 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, security issuances, term loans, short-term debt, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon regulatory approval, prevailing market conditions, and other factors. In 2012, the Company received $700 million in capital contributions from Southern Company. On January 31, 2013, the Company received $100 million in additional capital contributions from Southern Company. See "Capital Requirements and Contractual Obligations" herein for additional information.

The Company has received $245.3 million in DOE CCPI2 grant funds that were used for the construction of the Kemper IGCC. An additional $25 million in CCPI2 grant funds is expected to be received for the initial operation of the Kemper IGCC. On January 29, 2013, the Company withdrew its application for federal loan guarantees related to 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.

Investment tax credits related to the Kemper IGCC of $170.9 million are not expected to be utilized until after 2013, which could result in additional financing needs. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information.

The issuance of securities by the Company is subject to regulatory approval by the FERC. Additionally, with respect to the public offering of securities, the Company files registration statements with the Securities and Exchange Commission (SEC) under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the FERC, as well as the amounts registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in raising capital.

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 obligations 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.

At December 31, 2012, the Company had approximately $145.0 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2012 were as follows:

Expires[(a)]				Executable Term-Loans		Due Within One Year	
2013	2014	Total	Unused	One Year	Two Years	Term Out	No Term Out
(in millions)							
$135	$165	$300	$300	$25	$40	$65	$70

(a) No credit arrangements expire after 2014.

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 typically contain cross-default provisions that are restricted only to the indebtedness of the Company. The Company is currently in compliance with all such covenants. The Company expects to renew its credit arrangements, as needed prior to expiration.

These credit arrangements 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, 2012 was $40.1 million.

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 traditional operating company under these arrangements are several and there is no cross affiliate credit support.

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Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period		Short-term Debt During the Period (a)		
	Amount Outstanding (in millions)	Weighted Average Interest Rate	Average Outstanding (in millions)	Weighted Average Interest Rate	Maximum Amount Outstanding (in millions)
December 31, 2012:					
Commercial paper	$—	—%	$—	—%	$—
December 31, 2011:					
Commercial paper	$—	—%	$7	0.2%	$70
December 31, 2010:					
Commercial paper	$—	—%	$12	0.3%	$63

(a) Average and maximum amounts are based upon daily balances during the twelve-month periods ended December 31, 2012, 2011, and 2010.

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, contractual obligations, and storm restoration costs, 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.

Bank Term Loans

In March 2012, the Company paid at maturity a $75 million aggregate principal amount variable rate bank note bearing interest at a rate based on one-month London Interbank Offered Rate (LIBOR).

In September 2012, the Company paid at maturity a $40 million aggregate principal amount variable rate bank note bearing interest at a rate based on one-month LIBOR.

In November 2012, the Company entered into a 366-day $100 million aggregate principal amount floating rate term loan agreement that bears interest based on one-month LIBOR. The first advance in the amount of $50 million was made in November 2012. Subsequent to December 31, 2012, the second advance in the amount of $50 million was made. The proceeds of this loan were used solely for working capital and other general corporate purposes, including the Company's continuous construction program.

Senior Notes

In March 2012, the Company issued $250 million aggregate principal amount of Series 2012A 4.25% Senior Notes due March 15, 2042 and an additional $150 million aggregate principal amount of Series 2011A 2.35% Senior Notes due October 15, 2016. The Series 2011A Senior Notes were of the same series of notes that were originally issued in October 2011 in the aggregate principal amount of $150 million. Upon completion of this offering, the aggregate principal amount of the outstanding Series 2011A Senior Notes was $300 million. The proceeds from the sales of the Series 2012A Senior Notes and the Series 2011A Senior Notes were used to repay a bank term loan in an aggregate principal amount of $75 million, bearing interest at a variable rate based on one-month LIBOR, and for general corporate purposes, including the Company's continuous construction program.

In March 2012, $300 million in interest rate swaps were settled, of which $250 million related to the Series 2012A Senior Notes at a loss of approximately $13.3 million, which will be amortized to interest expense, in earnings, over 10 years, and $50 million related to the Series 2011A Senior Notes at a loss of approximately $2.7 million, which will be amortized to interest expense, in earnings, over 10 years.

In May 2012, the Company redeemed $90 million aggregate principal amount of Series E 5-5/8% Senior Notes due May 1, 2033.

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In August 2012, the Company issued an additional $200 million aggregate principal amount of Series 2012A 4.25% Senior Notes due March 15, 2042. The Series 2012A Senior Notes were of the same series of notes that were originally issued in March 2012 in the aggregate principal amount of $250 million. Upon completion of this offering, the aggregate principal amount of the outstanding Series 2012A Senior Notes is $450 million. The proceeds from this sale of the Series 2012A Senior Notes were used for general corporate purposes, including the Company's continuous construction program.

Other Revenue Bonds

In August 2012, the Mississippi Business Finance Corporation (MBFC) entered into an agreement to issue up to $42.50 million aggregate principal amount of MBFC Taxable Revenue Bonds, Series 2012A (Mississippi Power Company Project), up to $21.25 million aggregate principal amount of MBFC Taxable Revenue Bonds, Series 2012B (Mississippi Power Company Project), and up to $21.25 million aggregate principal amount of MBFC Taxable Revenue Bonds, Series 2012C (Mississippi Power Company Project) for the benefit of the Company. During 2012, the MBFC issued $8.97 million aggregate principal amount of MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2012A, $21.25 million aggregate principal amount of MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2012B, and $21.25 million aggregate principal amount of MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2012C for the benefit of the Company. The proceeds were used to reimburse the Company 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 2012A bonds will be used for this same purpose.

Other Obligations

In March 2012, the Company received a $150 million interest-bearing refundable deposit from SMEPA to be applied to the sale price for the pending sale of an undivided interest in the Kemper IGCC. Until the acquisition is closed, the deposit bears interest at the Company's AFUDC rate adjusted for income taxes, which was 9.967% per annum at December 31, 2012, and is 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 the Company 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.

Purchase of the Plant Daniel Combined Cycle Generating Units

In 2001, the Company began the initial 10-year term of an operating lease agreement for Plant Daniel Units 3 and 4. In October 2011, the Company purchased Plant Daniel Units 3 and 4 for $84.8 million in cash and the assumption of $270.0 million face value 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. Accounting rules require that Plant Daniel Units 3 and 4 be reflected on the Company's financial statements at the time of the purchase at the fair value of the consideration rendered. Based on interest rates as of October 20, 2011, the fair value of the debt assumed was $346.1 million. The fair value of the debt was determined using a discounted cash flow model based on the Company's borrowing rate at the closing date. The fair value is considered a Level 2 disclosure for financial reporting purposes. See Note 1 to the financial statements under "Purchase of the Plant Daniel Combined Cycle Generating Units" for additional information regarding the debt valuation. Accordingly, Plant Daniel Units 3 and 4 were reflected in the Company's financial statements at $430.9 million.

In connection with the purchase of Plant Daniel Units 3 and 4, the Company filed a request in July 2011 for an accounting order from the Mississippi PSC. This order, as approved on January 11, 2012, authorized the Company to defer as a regulatory asset, for the 10-year period ending October 2021, the difference between the revenue requirement under the purchase option for Plant Daniel Units 3 and 4 (assuming a remaining 30-year life) and the revenue requirement assuming the continuation of the operating lease regulatory treatment with the accumulated deferred balance at the end of the deferral being amortized into rates over the remaining life of Plant Daniel Units 3 and 4. In November 2011, the Company filed a request with the FERC seeking the same accounting and regulatory treatment for its wholesale cost-based jurisdiction. The total amount deferred in other regulatory assets, deferred at December 31, 2012 was $12.4 million. The ultimate outcome of this matter cannot be determined at this time.

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 for physical electricity sales, fuel purchases, fuel transportation and storage, emissions allowances, and energy price risk management. At December 31, 2012, the maximum potential collateral requirements under these contracts at a rating below BBB- and/or Baa3 were approximately $273 million.

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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.

In March 2012, the Company received a $150 million interest-bearing refundable deposit from SMEPA to be applied to the sale price for the pending sale of an undivided interest in the Kemper IGCC. Until the acquisition is closed, the deposit bears interest at the Company's AFUDC rate adjusted for income taxes, which was 9.967% per annum at December 31, 2012, and is 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 the Company 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 3, 2012, Fitch downgraded the issuer default and unsecured long-term debt ratings of the Company to A- from A and to A from A+, respectively. Fitch also announced that it had downgraded the pollution control revenue bond ratings of the Company to A from A+ and the preferred stock ratings of the Company to BBB+ from A-. Fitch revised the ratings outlook for the Company to negative from stable.

On August 6, 2012, Moody's downgraded the senior unsecured debt and preferred stock ratings of the Company to A3 from A2 and to Baa2 from Baa1, respectively. Moody's revised the ratings outlook for the Company to negative from stable.

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

To mitigate future exposure to changes in interest rates, the Company enters into derivatives that have been designated as hedges. The weighted average interest rate on $266.5 million of outstanding variable rate long-term debt at December 31, 2012 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 $2.7 million at January 1, 2013. See Note 1 to the financial statements under "Financial Instruments" and Note 10 to the financial statements for additional information.

To mitigate residual risks relative to movements in electricity prices, the Company enters into fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market. The Company continues to manage retail fuel hedging programs implemented per the guidelines of the Mississippi PSC and wholesale fuel hedging programs under agreements with wholesale customers. The Company had no material change in market risk exposure for the year ended December 31, 2012 when compared to the December 31, 2011 reporting period.

The changes in fair value of energy-related derivative contracts, substantially all of which are composed of regulatory hedges, for the years ended December 31 were as follows:

	2012 Changes	2011 Changes
	Fair Value	
	(in thousands)	

Contracts outstanding at the beginning of the period, assets (liabilities), net	$(50,990)	$(43,770)
Contracts realized or settled	43,326	32,381
Current period changes[a]	(9,263)	(39,601)
Contracts outstanding at the end of the period, assets (liabilities), net	$(16,927)	$(50,990)

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

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The changes in the fair value positions of the energy-related derivative contracts, which are substantially all attributable to both the volume and the price of natural gas, for the years ended December 31 were as follows:

	2012 Changes	2011 Changes
	Fair Value (in thousands)	
Natural gas swaps	$26,020	$1,066
Natural gas options	8,085	(8,286)
Other energy related derivatives	(42)	—
Total changes	$34,063	$(7,220)

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

	2012	2011
	mmBtu* Volume (in thousand)	
Commodity – Natural gas swaps	38,130	21,660
Commodity – Natural gas options	—	9,350
Total hedge volume	38,130	31,010

* million British thermal units (mmBtu)

The weighted average swap contract cost above market prices was approximately $0.44 per mmBtu as of December 31, 2012 and $1.98 per mmBtu as of December 31, 2011. 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 costs associated with natural gas hedges are recovered through the Company's energy cost management clauses.

At December 31, 2012 and 2011, 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 ECM clause. Gains and losses on energy-related derivatives that are designated as cash flow hedges are used to hedge anticipated purchases and sales and 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 pre-tax gains and losses reclassified from other comprehensive income to revenue and fuel expense were not material for any period presented and are not expected to be material for 2013.

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 9 to the financial statements for further discussion of fair value measurements. The maturities of the energy-related derivative contracts, which are all Level 2 of the fair value hierarchy, at December 31, 2012 were as follows:

	Fair Value Measurements December 31, 2012			
	Total Fair Value	Maturity Year 1	Years 2&3	Years 4&5
	(in thousands)			
Level 1	$—	$—	$—	$—
Level 2	(16,927)	(12,478)	(4,730)	281
Level 3	—	—	—	—
Fair value of contracts outstanding at end of period	$(16,927)	$(12,478)	$(4,730)	$281

The Company is exposed to market price risk in the event of nonperformance by counterparties to the energy-related derivative contracts. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Note 1 to the financial statements under "Financial Instruments" and Note 10 to the financial statements.

Capital Requirements and Contractual Obligations

The construction program of the Company consists of a base level capital investment and capital expenditures to comply with existing environmental statutes and regulations. Included in the estimated base level capital investment amounts are expenditures related to the construction of the Kemper IGCC of $513 million and $218 million in 2013 and 2014, respectively, which are net of SMEPA's 15% proposed ownership share of the construction of the Kemper IGCC of approximately $492 million and $28 million in 2013 and 2014, respectively. The estimated share for SMEPA in 2013 reflects estimated construction costs relating to SMEPA's proposed ownership interest to be incurred through December 31, 2013 (including construction costs for all prior years relating to its proposed ownership interest). These estimated base level capital investment amounts also include capital expenditures covered under LTSAs, as well as capital expenditures and compliance costs associated with the MATS rule. Proposed water and coal combustion byproducts rules are not included in the construction program base level capital investment.

The Company's base level construction program investments for existing environmental statutes and regulations and the estimated incremental compliance costs related to the proposed water and coal combustion byproducts rules over the 2013 through 2015 three-year period, based on the assumption that coal combustion byproducts will continue to be regulated as non-hazardous solid waste under the proposed rule, are estimated as follows:

	2013	2014	2015
Construction program:	(in millions)		
Base capital	$667	$324	$139
Existing environmental statutes and regulations, including the MATS rule	129	174	116
Total construction program base level capital investment	$796	$498	$255
Potential incremental environmental compliance investment:			
Proposed water and coal combustion byproducts rules	$—	$6	$28

See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" and – "Integrated Coal Gasification Combined Cycle" for additional information.

The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; storm impacts; changes in environmental statutes and regulations; the outcome of any legal challenges to environmental rules; changes in generating plants, including unit retirements and replacements and adding or changing fuel sources at existing units, to meet regulatory requirements; changes in FERC rules and regulations; Mississippi PSC approvals; changes in the expected environmental compliance program; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information.

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

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preferred stock dividends, leases, and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 1, 2, 5, 6, 7, and 10 to the financial statements for additional information.

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Contractual Obligations

	2013	2014-2015	2016-2017	After 2017	Uncertain Timing [d]	Total
	(in thousands)					
Long-term debt[a] —						
Principal	$276,471	$—	$335,000	$1,157,695	$—	$1,769,166
Interest	71,290	132,879	125,829	819,619	—	1,149,617
Preferred stock dividends[b]	1,733	3,465	3,465	—	—	8,663
Financial derivative obligations[c]	13,116	6,202	165	—	—	19,483
Unrecognized tax benefits[d]	3,562	—	—	—	3,997	7,559
Operating leases [e]	11,232	11,648	1,920	—	—	24,800
Purchase commitments —						
Capital[f]	757,037	752,522	—	—	—	1,509,559
Fuel[g]	349,197	378,355	176,500	159,221	—	1,063,273
Long-term service agreements[h]	21,032	43,893	17,148	—	—	82,073
Pension and other postretirement benefits plans[i]	5,602	12,172	—	—	—	17,774
Total	$1,510,272	$1,341,136	$660,027	$2,136,535	$3,997	$5,651,967

(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, 2013, 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.

(b) Preferred stock does not mature; therefore, amounts are provided for the next five years only.

(c) For additional information, see Notes 1 and 10 to the financial statements.

(d) The timing related to the realization of $4.0 million in unrecognized tax benefits in individual years beyond 12 months cannot be reasonably and reliably estimated due to uncertainties in the timing of the effective settlement of tax positions. See Note 5 to the financial statements under "Unrecognized Tax Benefits" for additional information.

(e) See Note 7 to the financial statements for additional information.

(f) The Company provides estimated capital expenditures for a three-year period, including capital expenditures and compliance costs associated with existing environmental regulations, including the MATS rule. Such amounts exclude the Company's estimates of potential incremental environmental compliance investment to comply with proposed water and coal combustion byproducts rules, which are approximately $6 million and $28 million for years 2014 and 2015, respectively. Estimates reflect the proposed sale of 15% of the Kemper IGCC to SMEPA. At December 31, 2012, significant purchase commitments were outstanding in connection with the construction program. These amounts exclude capital expenditures covered under long-term service agreements, which are reflected separately. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" for additional information. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information.

(g) Includes commitments to purchase coal and natural gas, as well as the related transportation and storage. In most cases, these contracts contain provisions for price escalation, minimum purchase levels, and other financial commitments. Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected for natural gas purchase commitments have been estimated based on the New York Mercantile Exchange future prices at December 31, 2012.

(h) 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.

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Cautionary Statement Regarding Forward-Looking Statements
The Company's 2012 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail sales, retail rates, customer growth, 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 and postretirement benefit plan, financing activities, start and completion of construction projects, plans and estimated costs for new generation resources, filings with state and federal regulatory authorities, impact of the Tax Relief Act, impact of the ATRA, estimated sales and purchases under new power sale and purchase agreements, storm damage cost recovery and repairs, economic recovery, 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 byproducts, and emissions of sulfur, nitrogen, carbon, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, financial reform legislation, 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, the pending EPA civil action, and IRS 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, 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, including the development and construction of facilities with designs that have not been finalized or previously constructed, 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 benefit plans;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms;
- regulatory approvals and legislative actions related to the Kemper IGCC, including Mississippi PSC approvals and legislation relating to cost recovery for the Kemper IGCC, the SMEPA purchase decision, satisfaction of requirements to utilize investment tax credits and grants, and the outcome of any proceedings regarding the Mississippi PSC's issuance of the CPCN for the Kemper IGCC;
- 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, as well as potential impacts on the availability or benefits of proposed DOE loan guarantees;

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Mississippi Power Company 2012 Annual Report

- 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.

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STATEMENTS OF INCOME
For the Years Ended December 31, 2012, 2011, and 2010
Mississippi Power Company 2012 Annual Report

	2012	2011	2010
	(in thousands)		
Operating Revenues:			
Retail revenues	$747,453	$792,463	$797,912
Wholesale revenues, non-affiliates	255,557	273,178	287,917
Wholesale revenues, affiliates	16,403	30,417	41,614
Other revenues	16,583	16,819	15,625
Total operating revenues	1,035,996	1,112,877	1,143,068
Operating Expenses:			
Fuel	411,226	490,415	501,830
Purchased power, non-affiliates	5,221	6,239	8,426
Purchased power, affiliates	49,907	65,574	75,230
Other operations and maintenance	228,675	266,395	268,063
Depreciation and amortization	86,510	80,337	76,891
Taxes other than income taxes	79,445	70,127	69,810
Total operating expenses	860,984	979,087	1,000,250
Operating Income	175,012	133,790	142,818
Other Income and (Expense):			
Allowance for equity funds used during construction	64,793	24,707	3,795
Interest income	745	1,347	215
Interest expense, net of amounts capitalized	(40,838)	(21,691)	(22,341)
Other income (expense), net	519	(45)	3,738
Total other income and (expense)	25,219	4,318	(14,593)
Earnings Before Income Taxes	200,231	138,108	128,225
Income taxes	50,391	42,193	46,275
Net Income	149,840	95,915	81,950
Dividends on Preferred Stock	1,733	1,733	1,733
Net Income After Dividends on Preferred Stock	$148,107	$94,182	$80,217

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

STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2012, 2011, and 2010
Mississippi Power Company 2012 Annual Report

	2012	2011	2010
	(in thousands)		
Net Income	$149,840	$95,915	$81,950
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $(296), $(5,494), and $1, respectively	(479)	(8,870)	2
Reclassification adjustment for amounts included in net income, net of tax of $411, $(18), and $-, respectively	663	(29)	—
Total other comprehensive income (loss)	184	(8,899)	2
Comprehensive Income	$150,024	$87,016	$81,952

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

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STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2012, 2011, and 2010
Mississippi Power Company 2012 Annual Report

	2012	2011	2010
	(in thousands)		
Operating Activities:			
Net income	$149,840	$95,915	$81,950
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization, total	86,981	83,787	82,294
Deferred income taxes	47,523	71,764	37,557
Investment tax credits received	82,464	—	22,173
Allowance for equity funds used during construction	(64,793)	(24,707)	(3,795)
Pension, postretirement, and other employee benefits	(35,425)	3,169	(34,911)
Hedge settlements	(15,983)	848	—
Stock based compensation expense	2,084	1,548	1,186
Generation construction screening costs	—	—	(50,554)
Regulatory assets associated with Kemper IGCC	(15,445)	(7,719)	(12,292)
Other, net	10,516	(433)	8,888
Changes in certain current assets and liabilities —			
-Receivables	(6,589)	5,864	(8,185)
-Fossil fuel stock	(36,206)	(27,933)	14,997
-Materials and supplies	(3,473)	(2,116)	(879)
-Prepaid income taxes	(3,852)	12,907	(17,075)
-Other current assets	(19,851)	1,606	(4,633)
-Other accounts payable	8,814	24,143	(12,630)
-Accrued interest	17,627	6,817	194
-Accrued taxes	13,768	1,209	(4,268)
-Accrued compensation	(183)	(187)	2,291
-Over recovered regulatory clause revenues	16,836	(16,544)	28,450
-Other current liabilities	757	1,557	1,943
Net cash provided from operating activities	235,410	231,495	132,701
Investing Activities:			
Property additions	(1,620,047)	(964,233)	(247,005)
Plant acquisition	—	(84,803)	—
Investment in restricted cash	—	—	(50,000)
Distribution of restricted cash	—	50,000	—
Cost of removal net of salvage	(4,355)	(7,432)	(9,240)
Construction payables	78,961	97,079	33,767
Capital grant proceeds	13,372	232,442	23,657
Other investing activities	(16,706)	(5,736)	(5,587)
Net cash used for investing activities	(1,548,775)	(682,683)	(254,408)
Financing Activities:			
Proceeds —			
Capital contributions from parent company	702,971	299,305	65,215
Bonds-Other	51,471	—	—
Senior notes issuances	600,000	300,000	—

Interest-bearing refundable deposit related to asset sale	150,000	—	—
Other long-term debt issuances	50,000	115,000	225,000
Redemptions —			
Capital leases	(633)	(1,437)	(1,330)
Senior notes	(90,000)	—	—
Other long-term debt	(115,000)	(130,000)	—
Payment of preferred stock dividends	(1,733)	(1,733)	(1,733)
Payment of common stock dividends	(106,800)	(75,500)	(68,600)
Other financing activities	6,512	(3,641)	(1,091)
Net cash provided from (used for) financing activities	1,246,788	501,994	217,461
Net Change in Cash and Cash Equivalents	(66,577)	50,806	95,754
Cash and Cash Equivalents at Beginning of Year	211,585	160,779	65,025
Cash and Cash Equivalents at End of Year	$145,008	$211,585	$160,779
Supplemental Cash Flow Information:			
Cash paid during the period for —			
Interest (net of $32,816, $10,065 and $2,903 capitalized, respectively)	$32,589	$14,814	$19,518
Income taxes (net of refunds)	(77,580)	(41,024)	7,546
Noncash transactions — accrued property additions at year-end	214,863	135,902	37,736
Assumption of debt due to plant acquisition	—	346,051	—

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

BALANCE SHEETS
At December 31, 2012 and 2011
Mississippi Power Company 2012 Annual Report

Assets	2012	2011
	(in thousands)	
Current Assets:		
Cash and cash equivalents	$145,008	$211,585
Receivables —		
Customer accounts receivable	29,561	32,551
Unbilled revenues	32,688	27,239
Other accounts and notes receivable	7,517	7,080
Affiliated companies	27,160	23,078
Accumulated provision for uncollectible accounts	(373)	(547)
Fossil fuel stock, at average cost	176,378	140,173
Materials and supplies, at average cost	34,260	30,787
Other regulatory assets, current	55,302	69,201
Prepaid income taxes	129,835	37,793
Other current assets	17,170	8,881
Total current assets	654,506	587,821
Property, Plant, and Equipment:		
In service	3,036,159	2,902,240
Less accumulated provision for depreciation	1,065,474	1,019,251
Plant in service, net of depreciation	1,970,685	1,882,989
Construction work in progress	2,471,145	955,135
Total property, plant, and equipment	4,441,830	2,838,124
Other Property and Investments	4,887	6,520
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	71,869	25,009
Other regulatory assets, deferred	236,225	185,694
Other deferred charges and assets	42,304	28,674
Total deferred charges and other assets	350,398	239,377
Total Assets	$5,451,621	$3,671,842

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

BALANCE SHEETS
At December 31, 2012 and 2011
Mississippi Power Company 2012 Annual Report

Liabilities and Stockholder's Equity	2012	2011
	(in thousands)	
Current Liabilities:		
Securities due within one year	$276,471	$240,633
Interest-bearing refundable deposit related to asset sale	150,000	—
Accounts payable —		
Affiliated	54,769	62,650
Other	262,992	168,309
Customer deposits	14,202	13,658
Accrued taxes —		
Accrued income taxes	2,339	3,813
Other accrued taxes	69,376	53,825
Accrued interest	30,376	12,750
Accrued compensation	15,706	15,889
Other regulatory liabilities, current	5,376	5,779
Over recovered regulatory clause liabilities	77,338	60,502
Liabilities from risk management activities	13,116	54,127
Other current liabilities	18,766	17,533
Total current liabilities	990,827	709,468
Long-Term Debt (See accompanying statements)	1,564,462	1,103,596
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	274,793	270,397
Deferred credits related to income taxes	10,106	11,058
Accumulated deferred investment tax credits	370,554	109,761
Employee benefit obligations	157,421	161,065
Other cost of removal obligations	143,461	126,424
Other regulatory liabilities, deferred	56,984	60,848
Other deferred credits and liabilities	52,860	37,228
Total deferred credits and other liabilities	1,066,179	776,781
Total Liabilities	3,621,468	2,589,845
Cumulative Redeemable Preferred Stock (See accompanying statements)	32,780	32,780
Common Stockholder's Equity (See accompanying statements)	1,797,373	1,049,217
Total Liabilities and Stockholder's Equity	$5,451,621	$3,671,842
Commitments and Contingent Matters (See notes)		

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

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STATEMENTS OF CAPITALIZATION
At December 31, 2012 and 2011
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	2012	2011	2012	2011
	(in thousands)		(percent of total)	
Long-Term Debt:				
Long-term notes payable —				
6.00% due 2013	$50,000	$50,000		
2.35% due 2016	300,000	150,000		
5.60% due 2017	35,000	35,000		
2.25% to 5.63% due 2019-2042	805,000	445,000		
Adjustable rates (0.60% to 0.85% at 1/1/12) due 2012	—	240,000		
Adjustable rates (0.63% to 1.21% at 1/1/13) due 2013	226,471	—		
Total long-term notes payable	1,416,471	920,000		
Other long-term debt —				
Pollution control revenue bonds:				
5.15% due 2028	42,625	42,625		
Variable rates (0.12% to 0.14% at 1/1/13) due 2020-2028	40,070	40,070		
Plant Daniel revenue bonds (7.13%) due 2021	270,000	270,000		
Total other long-term debt	352,695	352,695		
Capitalized lease obligations	—	633		
Unamortized debt premium	80,912	74,551		
Unamortized debt discount	(9,145)	(3,650)		
Total long-term debt (annual interest requirement — $71.3 million)	1,840,933	1,344,229		
Less amount due within one year	276,471	240,633		
Long-term debt excluding amount due within one year	1,564,462	1,103,596	46.1 %	50.5 %
Cumulative Redeemable Preferred Stock:				
$100 par value				
Authorized: 1,244,139 shares				
Outstanding: 334,210 shares				
4.40% to 5.25% (annual dividend requirement — $1.7 million)	32,780	32,780	1.0	1.5
Common Stockholder's Equity:				
Common stock, without par value —				
Authorized: 1,130,000 shares				
Outstanding: 1,121,000 shares	37,691	37,691		
Paid-in capital	1,401,520	694,855		
Retained earnings	366,875	325,568		
Accumulated other comprehensive income (loss)	(8,713)	(8,897)		
Total common stockholder's equity	1,797,373	1,049,217	52.9	48.0
Total Capitalization	$3,394,615	$2,185,593	100.0 %	100.0 %

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

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STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
For the Years Ended December 31, 2012, 2011, and 2010
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	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
	(in thousands)					
Balance at December 31, 2009	1,121	$37,691	$325,562	$295,269	$—	$658,522
Net income after dividends on preferred stock	—	—	—	80,217	—	80,217
Capital contributions from parent company	—	—	67,228	—	—	67,228
Other comprehensive income (loss)	—	—	—	—	2	2
Cash dividends on common stock	—	—	—	(68,600)	—	(68,600)
Other	—	—	—	(1)	—	(1)
Balance at December 31, 2010	1,121	37,691	392,790	306,885	2	737,368
Net income after dividends on preferred stock	—	—	—	94,182	—	94,182
Capital contributions from parent company	—	—	302,065	—	—	302,065
Other comprehensive income (loss)	—	—	—	—	(8,899)	(8,899)
Cash dividends on common stock	—	—	—	(75,500)	—	(75,500)
Other	—	—	—	1	—	1
Balance at December 31, 2011	1,121	37,691	694,855	325,568	(8,897)	1,049,217
Net income after dividends on preferred stock	—	—	—	148,107	—	148,107
Capital contributions from parent company	—	—	706,665	—	—	706,665
Other comprehensive income (loss)	—	—	—	—	184	184
Cash dividends on common stock	—	—	—	(106,800)	—	(106,800)
Balance at December 31, 2012	1,121	$37,691	$1,401,520	$366,875	$(8,713)	$1,797,373

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

NOTES TO FINANCIAL STATEMENTS
Mississippi Power Company 2012 Annual Report
1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES
General
Mississippi 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 – Alabama Power Company (Alabama Power), Georgia Power Company (Georgia Power), Gulf Power Company (Gulf Power), and the 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 in southeast Mississippi 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.
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.
The Company is subject to regulation by the Federal Energy Regulatory Commission (FERC) and the Mississippi 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 and power pool transactions. Costs for these services amounted to $212.7 million, $185.5 million, and $125.1 million during 2012, 2011, and 2010, respectively. The increase in 2012 and 2011 SCS costs is primarily due to the construction of the new integrated coal gasification combined cycle (IGCC) electric generating plant located in Kemper County, Mississippi (Kemper IGCC) and the construction of a flue gas desulfurization system (scrubber) on Plant Daniel Units 1 and 2. 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 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 Alabama Power under which the Company owns a portion of Greene County Steam Plant. Alabama Power operates Greene County Steam Plant, and the Company reimburses Alabama Power for its proportionate share of non-fuel expenditures and costs, which totaled $11.7 million, $12.2 million, and $11.2 million in 2012, 2011, and 2010, respectively. Also, the Company reimburses Alabama Power for any direct fuel purchases delivered from an Alabama Power transfer facility, which were $28.1 million in 2012, $20.9 million in 2011, and $16.1 million in 2010. The Company also has an agreement with Gulf Power under which Gulf Power owns

a portion of Plant Daniel. The Company operates Plant Daniel, and Gulf Power reimburses the Company for its proportionate share of all associated expenditures and costs, which totaled $21.2 million, $23.3 million, and $25.0 million in 2012, 2011, and 2010, respectively. See Note 4 for additional information.

The Company also provides incidental services to and receives such services from other Southern Company subsidiaries which are generally minor in duration and amount. Except as described herein, the Company neither provided nor received any material services to or from affiliates in 2011 and 2010. The Company received storm assistance from other Southern Company subsidiaries totaling $2.0 million in 2012. There was no significant storm assistance received from affiliates in 2011 or 2010.

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.

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Mississippi Power Company 2012 Annual Report

New Accounting Pronouncements

In June 2011, the Financial Accounting Standards Board (FASB) issued guidance, ASU 2011-05, Presentation of Comprehensive Income, requiring companies to present the total of comprehensive income, the components of net income, and the components of other comprehensive income, in a single continuous statement of comprehensive income or in two separate but consecutive statements. In October 2012, the FASB issued additional guidance, ASU 2012-04, Technical Corrections and Improvements (ASU 2012-04), in which it clarified that those companies presenting consecutive statements must begin the statement of comprehensive income with net income. The Company retroactively adopted the guidance in ASU 2012-04 beginning with its financial statements for the three years ended December 31, 2012, 2011, and 2010.

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.

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

	2012	2011	Note
	(in thousands)		
Retiree benefit plans	$162,293	$130,678	(a,g)
Property damage	(58,789)	(64,748)	(i)
Deferred income tax charges	68,175	21,000	(c)
Property tax	27,882	18,484	(d)
Vacation pay	9,635	9,128	(e,g)
Loss on reacquired debt	9,815	7,171	(k)
Plant Daniel Units 3 and 4 regulatory assets	12,386	3,945	(j)
Other regulatory assets	2,035	132	(b)
Fuel hedging (realized and unrealized) losses	20,906	54,103	(f,g)
Asset retirement obligations	9,353	9,057	(c)
Deferred income tax credits	(11,157)	(12,081)	(c)
Other cost of removal obligations	(143,461)	(126,424)	(c)
Fuel hedging (realized and unrealized) gains	(2,519)	(162)	(f,g)
Kemper IGCC regulatory assets	36,047	20,684	(h)
Other regulatory liabilities	—	(693)	(b)
Deferred income tax charges — Medicare subsidy	4,868	5,521	(l)
Total regulatory assets (liabilities), net	$147,469	$75,795	

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) Recorded and recovered as approved by the Mississippi PSC.

(c) Asset retirement and removal assets and liabilities and deferred income tax assets are recovered, and removal assets 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.

(d) Recovered through the ad valorem tax adjustment clause over a 12-month period beginning in April of the following year.

(e)

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

(f) 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, costs are recovered through the Energy Cost Management clause (ECM).

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

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

(i) For additional information, see Note 1 under "Provision for Property Damage" and Note 3 under "Retail Regulatory Matters – System Restoration Rider."

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Mississippi Power Company 2012 Annual Report

(j) Recovered and amortized over a 10-year period ending October 2021, as approved by the Mississippi PSC for the difference between the revenue requirement under the purchase option and the revenue requirement assuming operating lease accounting treatment for the extended term.

(k) Recovered over the remaining life of the original issue or, if refinanced, over the life of the new issue, which may range up to 50 years.

(l) Recovered and amortized over a 10-year period beginning in 2012, as approved by the Mississippi PSC for the retail portion and a five-year period for the wholesale portion, as approved by FERC.

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" and "Integrated Coal Gasification Combined Cycle" for additional information.

Government Grants

In 2008, the Company requested that the Department of Energy (DOE) transfer the remaining funds previously granted under the Clean Coal Power Initiative Round 2 (CCPI2) from a cancelled IGCC project of one of Southern Company's subsidiaries that would have been located in Orlando, Florida. In 2010, the DOE, through a cooperative agreement with SCS, agreed to fund $270.0 million of the Kemper IGCC through the CCPI2 funds. Through December 31, 2012, the Company has received grant funds of $245.3 million, used for the construction of the Kemper IGCC, which is reflected in the Company's financial statements as a reduction to the Kemper IGCC capital costs. An additional $25.0 million is expected to be received for its initial operation.

Revenues

Energy and other revenues are recognized as services are provided. Wholesale capacity revenues from long-term contracts are recognized at the lesser of the levelized amount or the amount billable under the contract over the respective contract period. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. The Company's retail and wholesale rates include provisions to adjust billings for fluctuations in fuel costs, fuel hedging, the energy component of purchased power costs, and certain other costs. Retail rates also include provisions to adjust billings for fluctuations in costs for ad valorem taxes and certain qualifying environmental costs. Revenues are adjusted for differences between these actual costs and amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors. The Company is required to file with the Mississippi PSC for an adjustment to the fuel cost recovery factor annually.

The Company 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 the Company's total operating revenues in 2012 and are largely subject to rolling 10-year cancellation notices.

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 costs also include gains and/or losses from fuel hedging programs as approved by the Mississippi PSC.

Income and Other Taxes

The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. Investment tax credits 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.

NOTES (continued)
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Property, Plant, and Equipment

Property, plant, and equipment is stated at original cost less any regulatory disallowances and impairments. Original cost includes: materials; labor; minor items of property; appropriate administrative and general costs; payroll-related costs such as taxes, pensions, and other benefits; and the interest capitalized and cost of equity funds used during construction for projects where recovery of construction work in progress (CWIP) is not allowed in rates.

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

	2012	2011
	(in thousands)	
Generation	$1,363,269	$1,362,567
Transmission	563,037	497,202
Distribution	802,718	784,655
General	225,723	176,408
Plant acquisition adjustment	81,412	81,408
Total plant in service	$3,036,159	$2,902,240

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 expense except for the cost of maintenance of coal cars and a portion of the railway track maintenance costs, which are charged to fuel stock and recovered through the Company's fuel clause.

Purchase of the Plant Daniel Combined Cycle Generating Units

In 2001, the Company began the initial 10-year term of an operating lease agreement for the combined cycle generating Units 3 and 4 at Plant Daniel (Plant Daniel Units 3 and 4). In October 2011, the Company purchased Plant Daniel Units 3 and 4 for $84.8 million in cash and the assumption of $270.0 million face value 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. Accounting rules require that Plant Daniel Units 3 and 4 be reflected on the Company's financial statements at the time of the purchase at the fair value of the consideration rendered. Based on interest rates as of October 20, 2011, the fair value of the debt assumed was $346.1 million. The fair value of the debt was determined using a discounted cash flow model based on the Company's borrowing rate at the closing date. The fair value is considered a Level 2 disclosure for financial reporting purposes. Accordingly, Plant Daniel Units 3 and 4 were reflected in the Company's financial statements as follows:

	(in thousands)
Assumption of debt obligations	$270,000
Fair value adjustment at date of purchase	76,051
Total debt	346,051
Cash payment for the purchase	84,803
Total value of Plant Daniel Units 3 and 4	$430,854

See Note 3 under "Retail Regulatory Matters – Performance Evaluation Plan" for additional information.

Depreciation and Amortization

Depreciation of the original cost of plant in service is provided primarily by using composite straight-line rates, which approximated 3.5% in 2012, 3.9% in 2011, and 3.4% in 2010. Depreciation studies are conducted periodically to update the composite rates. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. Minor items of property included in the original cost of the plant are retired when the related property unit is retired. Depreciation includes an amount for the expected cost of removal of facilities. In 2009, the Company filed a depreciation study as of December 31, 2008 with the Mississippi PSC and the FERC. The FERC accepted this study in 2009. In 2010, the Mississippi PSC issued an order approving the depreciation rates effective in 2010. This change did not have a material impact on the financial statements.

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The Company, in compliance with FERC guidance, classified $81.4 million as a plant acquisition adjustment on the purchase of Plant Daniel Units 3 and 4. This includes $76.1 million recorded in conjunction with the premium on long-term debt and is being amortized over 10 years beginning October 2011. See "Purchase of the Plant Daniel Combined Cycle Generating Units" herein for additional information.

On January 11, 2012, the Mississippi PSC issued an order allowing the Company to defer in a regulatory asset the difference between the revenue requirement under the purchase option of Plant Daniel Units 3 and 4 and the revenue requirement assuming operating lease accounting treatment for the extended term. The regulatory asset will be deferred for a 10-year period ending October 2021. At the conclusion of the deferral period, the unamortized deferral balance will be amortized into rates over the remaining life of the units.

In 2007, the Mississippi PSC issued an order allowing the Company to defer certain reliability related maintenance costs beginning in 2007 and recover them evenly over a four-year period beginning in 2008. These costs related to maintenance that was needed as follow-up to emergency repairs that were made subsequent to Hurricane Katrina. At December 31, 2011, the Company had fully amortized these costs.

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. The Company has received accounting guidance from the Mississippi PSC allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations are reflected in the balance sheets as a regulatory liability.

The Company has retirement obligations related to various landfill sites, ash ponds, underground storage tanks, deep injection wells, water wells, substation removal, mine reclamation, and asbestos removal. The Company also has identified retirement obligations related to certain transmission and distribution facilities, co-generation facilities, certain wireless communication towers, and certain structures authorized by the U.S. Army Corps of Engineers. However, liabilities for the removal of these assets have not been recorded because the range of time over which the Company may settle these obligations is unknown and cannot be reasonably estimated. 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 Mississippi PSC, and are reflected in the balance sheets.

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

	2012	2011
	(in thousands)	
Balance at beginning of year	$19,148	$18,601
Liabilities incurred	20,989	137
Liabilities settled	(282)	(644)
Accretion	1,874	1,054
Cash flow revisions	386	—
Balance at end of year	$42,115	$19,148

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 over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in the calculation of taxable income. The average annual AFUDC rate was 7.04%, 7.06%, and 7.33% for the years ended December 31, 2012, 2011, and 2010, respectively. The AFUDC rate is applied to CWIP consistent with jurisdictional regulatory treatment. AFUDC, net of income taxes, as a percentage of net income after dividends on preferred stock was 57.05%, 31.60%, and 6.97% for 2012, 2011, and 2010, respectively.

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Impairment of Long-Lived Assets and Intangibles
The Company evaluates long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether an impairment has occurred is based on either a specific regulatory disallowance or an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by either the amount of regulatory disallowance or by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. For assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell in order to determine if an impairment loss is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change.
Provision for Property Damage
The Company carries insurance for the cost of certain types of damage to generation plants and general property. However, the Company is self-insured for the cost of storm, fire, and other uninsured casualty damage to its property, including transmission and distribution facilities. As permitted by the Mississippi PSC and the FERC, the Company accrues for the cost of such damage through an annual expense accrual credited to regulatory liability accounts for the retail and wholesale jurisdictions. The cost of repairing actual damage resulting from such events that individually exceed $50,000 is charged to the reserve. In 2009, the Mississippi PSC approved the System Restoration Rider (SRR) stipulation between the Company and the Mississippi Public Utilities Staff (MPUS). In accordance with the stipulation, every three years the Mississippi PSC, MPUS, and the Company will agree on SRR revenue level(s) for the ensuing period, based on historical data, expected exposure, type and amount of insurance coverage, excluding insurance cost, and any other relevant information. The accrual amount and the reserve balance are determined based on the SRR revenue level(s). If a significant change in circumstances occurs, then the SRR revenue level can be adjusted more frequently if the Company and the MPUS or the Mississippi PSC deem the change appropriate. Each year the Company will set rates to collect the approved SRR revenues. The property damage reserve accrual will be the difference between the approved SRR revenues and the SRR revenue requirement, excluding any accrual to the reserve. In 2012, 2011, and 2010, the Company made retail accruals of $3.5 million, $3.8 million, and $3.1 million, respectively, per the annual SRR rate filings. In addition, SRR allows the Company to set up a regulatory asset, pending review, if the allowable actual retail property damage costs exceed the amount in the retail property damage reserve. See Note 3 under "Retail Regulatory Matters – System Restoration Rider" for additional information. The Company accrued $0.3 million annually in 2012, 2011 and in 2010 for the wholesale jurisdiction.
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 fuel cost recovery rates. The retail rate is approved by the Mississippi PSC while the wholesale rates are filed with the FERC. Emissions allowances granted by the 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, 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 9 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 the fair value accounting requirements because they qualify for the "normal" scope exception, and are accounted for under the accrual method. Fuel and interest rate derivative contracts qualify as cash flow hedges of anticipated transactions or are recoverable through the Mississippi PSC approved fuel hedging program as discussed below. This results in the deferral of related gains and losses in OCI or regulatory assets and liabilities, respectively, until the hedged transactions occur. Foreign currency exchange rate hedges are designated as fair value hedges.

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Settled foreign currency exchange hedges are booked as CWIP. Any ineffectiveness arising from these would be recognized currently in net income; however, the Company has regulatory approval allowing it to defer any ineffectiveness arising from hedging program instruments relating to the Kemper IGCC to a regulatory asset. Other derivative contracts are marked to market through current period income and are recorded on a net basis in the statements of income. The amounts related to derivatives on the cash flow statement are classified in the same category as the items being hedged. See Note 10 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 has no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2012.

The Mississippi PSC has approved the Company's request to implement an ECM which, among other things, allows the Company to utilize financial instruments to hedge its fuel commitments. Changes in the fair value of these financial instruments are recorded as regulatory assets or liabilities. Amounts paid or received as a result of financial settlement of these instruments are classified as fuel expense and are included in the ECM factor applied to customer billings. The Company's jurisdictional wholesale customers have a similar ECM mechanism, which has been approved by the FERC.

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

Comprehensive Income

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

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 is required to provide financing for all costs associated with the mine development and operation under a contract with Liberty Fuels Company, LLC, a subsidiary of North American Coal Corporation (Liberty Fuels), in conjunction with the construction of the Kemper IGCC. Liberty Fuels qualifies as a VIE for which the Company is the primary beneficiary. For the year ended 2011, Liberty Fuels did not have a material impact on the financial position and results of operations of the Company. For the year ended December 31, 2012, the VIE consolidation resulted in an ARO and an associated liability in the amounts of $21.0 million and $21.8 million, respectively. See Note 3 under "Integrated Coal Gasification Combined Cycle" for additional information.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). In December 2012, the Company contributed $43.0 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2013. The Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The Company funds its other postretirement trusts to the extent required by the FERC. For the year ending December 31, 2013, other postretirement trust contributions are expected to be less than $1 million.

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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 2009 for the 2010 plan year using discount rates for the pension plans and the other postretirement benefit plans of 5.92% and 5.83%, respectively, and an annual salary increase of 4.18%.

	2012	2011	2010
Discount rate:			
Pension plans	4.26 %	4.98 %	5.51 %
Other postretirement benefit plans	4.04	4.87	5.39
Annual salary increase	3.59	3.84	3.84
Long-term return on plan assets:			
Pension plans	8.20	8.45	8.45
Other postretirement benefit plans	6.96	7.53	7.65

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) is the weighted average medical care cost trend rate. The weighted average medical care cost trend rates used in measuring the APBO as of December 31, 2012 were as follows:

	Initial Cost Trend Rate	Ultimate Cost Trend Rate	Year That Ultimate Rate Is Reached
Pre-65	8.00%	5.00%	2020
Post-65 medical	6.00	5.00	2020
Post-65 prescription	6.00	5.00	2020

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, 2012 as follows:

	1 Percent Increase	1 Percent Decrease
	(in thousands)	
Benefit obligation	$6,000	$(5,099)
Service and interest costs	316	(268)

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Pension Plans
The total accumulated benefit obligation for the pension plans was $392 million at December 31, 2012 and $339 million at December 31, 2011. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2012 and 2011 were as follows:

	2012	2011
	(in thousands)	
Change in benefit obligation		
Benefit obligation at beginning of year	$369,680	$330,315
Service cost	9,416	8,838
Interest cost	18,019	17,827
Benefits paid	(14,949)	(14,587)
Plan amendments	—	—
Actuarial loss	50,387	27,287
Balance at end of year	432,553	369,680
Change in plan assets		
Fair value of plan assets at beginning of year	282,100	283,698
Actual return on plan assets	39,668	10,805
Employer contributions	44,930	2,184
Benefits paid	(14,949)	(14,587)
Fair value of plan assets at end of year	351,749	282,100
Accrued liability	$(80,804)	$(87,580)

At December 31, 2012, the projected benefit obligations for the qualified and non-qualified pension plans were $400 million and $32 million, respectively. All pension plan assets are related to the qualified pension plan.

Amounts recognized in the balance sheets at December 31, 2012 and 2011 related to the Company's pension plans consist of the following:

	2012	2011
	(in thousands)	
Other regulatory assets, deferred	$146,838	$117,354
Other current liabilities	(2,087)	(1,652)
Employee benefit obligations	(78,717)	(85,928)

Presented below are the amounts included in regulatory assets at December 31, 2012 and 2011 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 2013.

	2012	2011	Estimated Amortization in 2013
	(in thousands)		
Prior service cost	$5,261	$6,570	$1,143
Net (gain) loss	141,577	110,784	9,461
Other regulatory assets, deferred	$146,838	$117,354	

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The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2012 and 2011 are presented in the following table:

	Regulatory Assets (in thousands)
Balance at December 31, 2010	$ 78,130
Net (gain) loss	41,647
Change in prior service costs	—
Reclassification adjustments:	
Amortization of prior service costs	(1,309)
Amortization of net gain (loss)	(1,114)
Total reclassification adjustments	(2,423)
Total change	39,224
Balance at December 31, 2011	$ 117,354
Net (gain) loss	34,893
Change in prior service costs	—
Reclassification adjustments:	
Amortization of prior service costs	(1,309)
Amortization of net gain (loss)	(4,100)
Total reclassification adjustments	(5,409)
Total change	29,484
Balance at December 31, 2012	$ 146,838

Components of net periodic pension cost were as follows:

	2012	2011	2010
	(in thousands)		
Service cost	$9,416	$8,838	$8,300
Interest cost	18,019	17,827	17,916
Expected return on plan assets	(24,121)	(25,166)	(21,451)
Recognized net (gain) loss	4,100	1,114	634
Net amortization	1,309	1,309	1,391
Net periodic pension cost	$8,723	$3,922	$6,790

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

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Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2012, estimated benefit payments were as follows:

	Benefit Payments (in thousands)
2013	$16,282
2014	17,121
2015	17,947
2016	18,886
2017	20,001
2018 to 2022	117,471

Other Postretirement Benefits

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2012 and 2011 were as follows:

	2012	2011
	(in thousands)	
Change in benefit obligation		
Benefit obligation at beginning of year	$87,447	$81,688
Service cost	1,038	1,012
Interest cost	4,155	4,292
Benefits paid	(4,432)	(4,094)
Actuarial loss	3,166	4,073
Plan amendments	—	—
Retiree drug subsidy	409	476
Balance at end of year	91,783	87,447
Change in plan assets		
Fair value of plan assets at beginning of year	20,534	20,955
Actual return on plan assets	2,427	720
Employer contributions	3,052	2,477
Benefits paid	(4,023)	(3,618)
Fair value of plan assets at end of year	21,990	20,534
Accrued liability	$(69,793)	$(66,913)

Amounts recognized in the balance sheets at December 31, 2012 and 2011 related to the Company's other postretirement benefit plans consist of the following:

	2012	2011
	(in thousands)	
Other regulatory assets, deferred	$15,454	$13,324
Employee benefit obligations	(69,793)	(66,913)

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Presented below are the amounts included in regulatory assets at December 31, 2012 and 2011 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 2013.

	2012	2011	Estimated Amortization in 2013
	(in thousands)		
Prior service cost	$(2,498)	$(2,686)	$(188)
Net (gain) loss	17,952	15,839	659
Transition obligation	—	171	—
Other regulatory assets, deferred	$15,454	$13,324	

The changes in the balance of regulatory assets related to the other postretirement benefit plans for the plan years ended December 31, 2012 and 2011 are presented in the following table:

	Regulatory Assets (in thousands)
Balance at December 31, 2010	$8,618
Net (gain) loss	4,980
Change in prior service costs/transition obligation	—
Reclassification adjustments:	
Amortization of transition obligation	(228)
Amortization of prior service costs	188
Amortization of net gain (loss)	(234)
Total reclassification adjustments	(274)
Total change	4,706
Balance at December 31, 2011	$13,324
Net (gain) loss	2,600
Change in prior service costs/transition obligation	—
Reclassification adjustments:	
Amortization of transition obligation	(171)
Amortization of prior service costs	188
Amortization of net gain (loss)	(487)
Total reclassification adjustments	(470)
Total change	2,130
Balance at December 31, 2012	$15,454

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

	2012	2011	2010
	(in thousands)		
Service cost	$1,038	$1,012	$1,305
Interest cost	4,155	4,292	4,763
Expected return on plan assets	(1,552)	(1,763)	(1,826)
Net amortization	470	274	574
Net postretirement cost	$4,111	$3,815	$4,816

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Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the APBO for the other postretirement benefit plans. 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 thousands)		
2013	$5,174	$(601)	$4,573
2014	5,442	(663)	4,779
2015	5,754	(720)	5,034
2016	5,995	(782)	5,213
2017	6,280	(845)	5,435
2018 to 2022	33,822	(4,414)	29,408

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, 2012 and 2011, along with the targeted mix of assets for each plan, is presented below:

	Target	2012	2011
Pension plan assets:			
Domestic equity	26%	28%	29%
International equity	25	24	25
Fixed income	23	27	23
Special situations	3	1	—
Real estate investments	14	13	14
Private equity	9	7	9
Total	100%	100%	100%
Other postretirement benefit plan assets:			
Domestic equity	21%	22%	22%
International equity	20	19	20
Fixed income	39	42	40
Special situations	2	1	—
Real estate investments	11	10	11
Private equity	7	6	7
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, 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.

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Investment Strategies

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

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

Benefit Plan Asset Fair Values

Following are the fair value measurements for the pension plan and the other postretirement benefit plan assets as of December 31, 2012 and 2011. 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:

- Investments in equity securities: 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.
- Investments in fixed income securities: 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.
- Investments in private equity and real estate: 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.

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The fair values of pension plan assets as of December 31, 2012 and 2011 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, 2012:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in thousands)			
Assets:				
Domestic equity*	$51,433	$29,624	$—	$81,057
International equity*	40,337	43,303	—	83,640
Fixed income:				
U.S. Treasury, government, and agency bonds	—	22,820	—	22,820
Mortgage- and asset-backed securities	—	5,618	—	5,618
Corporate bonds	—	38,696	140	38,836
Pooled funds	—	17,656	—	17,656
Cash equivalents and other	209	24,251	—	24,460
Real estate investments	11,410	—	37,196	48,606
Private equity	—	—	26,240	26,240
Total	$103,389	$181,968	$63,576	$348,933

* 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.

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As of December 31, 2011:	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 thousands)			
Assets:				
Domestic equity*	$47,911	$22,115	$—	$70,026
International equity*	49,250	14,111	—	63,361
Fixed income:				
U.S. Treasury, government, and agency bonds	—	17,960	—	17,960
Mortgage- and asset-backed securities	—	5,605	—	5,605
Corporate bonds	—	34,552	112	34,664
Pooled funds	—	15,757	—	15,757
Cash equivalents and other	28	5,773	—	5,801
Real estate investments	9,119	—	32,434	41,553
Private equity	—	—	24,151	24,151
Total	$106,308	$115,873	$56,697	$278,878

* 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, 2012 and 2011 were as follows:

	2012 Real Estate Investments	Private Equity	2011 Real Estate Investments	Private Equity
	(in thousands)			
Beginning balance	$32,434	$24,151	$27,976	$26,475
Actual return on investments:				
Related to investments held at year end	4,629	44	2,964	(498)
Related to investments sold during the year	133	3,415	830	1,951
Total return on investments	4,762	3,459	3,794	1,453
Purchases, sales, and settlements	—	(1,370)	664	(3,777)
Transfers into/out of Level 3	—	—	—	—
Ending balance	$37,196	$26,240	$32,434	$24,151

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The fair values of other postretirement benefit plan assets as of December 31, 2012 and 2011 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, 2012:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in thousands)			
Assets:				
Domestic equity*	$2,561	$1,475	$—	$4,036
International equity*	2,008	2,156	—	4,164
Fixed income:				
U.S. Treasury, government, and agency bonds	—	5,187	—	5,187
Mortgage- and asset-backed securities	—	280	—	280
Corporate bonds	—	1,925	7	1,932
Pooled funds	—	879	—	879
Cash equivalents and other	11	1,612	—	1,623
Real estate investments	569	—	1,865	2,434
Private equity	—	14	1,293	1,307
Total	$5,149	$13,528	$3,165	$21,842

* 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.

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	Fair Value Measurements Using			
As of December 31, 2011:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in thousands)			
Assets:				
Domestic equity*	$2,733	$1,260	$—	$3,993
International equity*	2,807	804	—	3,611
Fixed income:				
U.S. Treasury, government, and agency bonds	—	4,796	—	4,796
Mortgage- and asset-backed securities	—	320	—	320
Corporate bonds	—	1,968	—	1,968
Pooled funds	—	898	—	898
Cash equivalents and other	1	987	—	988
Real estate investments	520	—	1,851	2,371
Private equity	—	—	1,377	1,377
Total	$6,061	$11,033	$3,228	$20,322

* 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, 2012 and 2011 were as follows:

	2012		2011	
	Real Estate Investments	Private Equity	Real Estate Investments	Private Equity
	(in thousands)			
Beginning balance	$1,851	$1,377	$1,625	$1,538
Actual return on investments:				
Related to investments held at year end	119	(1)	141	(29)
Related to investments sold during the year	7	90	47	85
Total return on investments	126	89	188	56
Purchases, sales, and settlements	(112)	(173)	38	(217)
Ending balance	$1,865	$1,293	$1,851	$1,377

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 2012, 2011, and 2010 were $3.9 million, $3.8 million, and $3.8 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 (CO_2) and other emissions, coal combustion byproducts, 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

In 1999, the EPA brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including Alabama Power and Georgia Power, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. The EPA alleged NSR violations at five coal-fired generating facilities operated by Alabama Power, including a unit co-owned by the Company, and three coal-fired generating facilities operated by Georgia Power. The civil action sought penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. These actions were filed concurrently with the issuance of notices of violation to the Company with respect to the Company's Plant Watson. The case against Georgia Power was administratively closed in 2001 and has not been reopened. After Alabama Power was dismissed from the original action, the EPA filed a separate action in 2001 against Alabama Power (including claims related to the unit co-owned by the Company) in the U.S. District Court for the Northern District of Alabama.

In 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree, resolving claims relating to the alleged NSR violations at Plant Miller. In 2010, the EPA dismissed five of its eight remaining claims against Alabama Power, leaving only three claims, including one relating to the unit co-owned by the Company. In March 2011, the U.S. District Court for the Northern District of Alabama granted Alabama Power summary judgment on all remaining claims and dismissed the case with prejudice. That judgment is on appeal to the U.S. Court of Appeals for the Eleventh Circuit. On February 23, 2012, the EPA filed a motion in the U.S. District Court for the Northern District of Alabama seeking vacatur of the judgment and recusal of the judge in the case involving Alabama Power.

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.

Climate Change Litigation

Kivalina Case

In 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs allege that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that some of the defendants (including Southern Company) acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. In 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case. On September 21, 2012, the U.S. Court of Appeals for the Ninth Circuit upheld the U.S. District Court for the Northern

District of California's dismissal of the case. On November 27, 2012, the U.S. Court of Appeals for the Ninth Circuit denied the plaintiffs' request for review of the decision. On February 25, 2013, the plaintiffs filed a petition for writ of certiorari with the U.S. Supreme Court. Southern Company believes that these claims are without merit. While Southern Company believes the likelihood of loss is remote based on existing case law, it is not possible to predict with certainty whether the Company will incur any liability in connection with this matter. The ultimate outcome of this matter cannot be determined at this time.

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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. The Company has authority from the Mississippi PSC to recover approved environmental compliance costs through regulatory mechanisms.
In 2003, the Texas Commission on Environmental Quality (TCEQ) designated the Company as a potentially responsible party at a site in Texas. The site was owned by an electric transformer company that handled the Company's transformers as well as those of many other entities. The site owner is bankrupt and the State of Texas has entered into an agreement with the Company and several other utilities to investigate and remediate the site. The feasibility study/presumptive remedy document was originally filed with TCEQ in June 2011 and remains under consideration by the agency. Amounts expensed and accrued during 2010, 2011, and 2012 related to this work were not material. Hundreds of entities have received notices from the TCEQ requesting their participation in the anticipated site remediation. The final impact of this matter on the Company will depend upon further environmental assessment and the ultimate number of potentially responsible parties. The remediation expenses incurred by the Company are expected to be recovered through the Environmental Compliance Overview (ECO) Plan.
The final outcome of this matter cannot now be determined. However, based on the currently known conditions at this site and the nature and extent of activities relating to this site, the Company does not believe that additional liabilities, if any, at this site would be material to the financial statements.
FERC Matters
In November 2011, the Company filed a request with the FERC for an increase in wholesale base revenues of approximately $32 million under the wholesale cost-based electric tariff. In its filing with the FERC, the Company sought (i) approval to establish a regulatory asset for the portion of non-capitalizable Kemper IGCC-related costs which have been and will continue to be incurred during the construction period for the Kemper IGCC, (ii) authorization to defer as a regulatory asset, for the 10-year period ending October 2021, the difference between the revenue requirement under the purchase option of Plant Daniel Units 3 and 4 (assuming a remaining 30-year life) and the revenue requirement assuming the continuation of the operating lease regulatory treatment with the accumulated deferred balance at the end of the deferral being amortized into wholesale rates over the remaining life of Plant Daniel Units 3 and 4, and (iii) authority to defer in a regulatory asset costs related to the retirement or partial retirement of generating units as a result of environmental compliance rules.
On March 9, 2012, the Company entered into a settlement agreement with its wholesale customers with respect to the Company's request for revised rates under the wholesale cost-based electric tariff. The settlement agreement provides that base rates under the cost-based electric tariff will increase by approximately $22.6 million over a 12-month period with revised rates effective April 1, 2012. A significant portion of the difference between the requested base rate increase and the agreed upon rate increase is due to a change in the CWIP recovery on the Kemper IGCC. Under the settlement agreement, a portion of CWIP will continue to accrue AFUDC. The tariff customers specifically agreed to the same regulatory treatment for tariff ratemaking as the treatment approved for retail ratemaking by the Mississippi PSC with respect to (i) the accounting for Kemper IGCC-related costs that cannot be capitalized, (ii) the accounting for the lease termination and purchase of Plant Daniel Units 3 and 4, and (iii) the establishment of a regulatory asset for certain potential plant retirement costs.
On March 28, 2012, the FERC approved a motion to place interim rates into effect beginning in May 2012. On September 27, 2012, the Company, with its wholesale customers, filed a final settlement agreement with the FERC. On November 5, 2012, the settlement judge certified the settlement agreement to the FERC with the recommendation that it be approved. The FERC has not yet approved the settlement agreement. The ultimate outcome of this matter cannot be determined at this time.
Retail Regulatory Matters

Performance Evaluation Plan

The Company’s retail base rates are set under the Performance Evaluation Plan (PEP), a rate plan approved by the Mississippi PSC. PEP was designed with the objective to reduce the impact of rate changes on the customer and provide incentives for the Company to keep customer prices low and customer satisfaction and reliability high. PEP is a mechanism for rate adjustments based on three indicators: price, customer satisfaction, and service reliability.

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In the 2004 order establishing the Company's forward-looking PEP, the Mississippi PSC ordered that the MPUS and the Company review the operations of the PEP in 2007. By mutual agreement, this review was deferred until 2008 and continued into 2009. In 2009, concurrent with this review, the annual PEP evaluation filing for 2009 was suspended and the MPUS and the Company filed a joint report with the Mississippi PSC proposing several changes to the PEP. The Mississippi PSC approved the revised PEP in 2009, which resulted in a lower performance incentive under the PEP and therefore smaller and/or less frequent rate changes in the future. Later that year, the Company resumed annual evaluations and filed its annual PEP filing for 2010 under the revised PEP, which resulted in a lower allowed return on investment but no rate change.

In 2010, the Company filed its annual PEP filing for 2011 under the revised PEP, which indicated a rate increase of 1.936%, or $16.1 million, annually. In January 2011, the MPUS contested the filing. In June 2011, the Mississippi PSC issued an order approving a joint stipulation between the MPUS and the Company resulting in no change in rates.

In November 2011, the Company filed its annual PEP filing for 2012, which indicated a rate increase of 1.893%, or $17.4 million, annually. On January 10, 2012, the MPUS contested the filing.

In March 2011, the Company submitted its annual PEP lookback filing for 2010, which recommended no surcharge or refund. In May 2011, the Company received a letter from the MPUS disputing certain items in the 2010 PEP lookback filing. On April 2, 2012, the Company filed a motion to suspend the PEP lookback filing for 2011. Unresolved matters related to certain costs included in the 2010 PEP lookback filing also impact the 2011 PEP lookback filing, making it impractical to determine the Company's actual retail return on investment for 2011 for purposes of the 2011 PEP lookback filing. An order granting the suspension of the 2011 PEP lookback was signed by the Mississippi PSC on May 8, 2012. On or before March 15, 2013, the Company will submit its annual PEP lookback filing for 2012. While the Company does not expect the resolution of these unresolved matters to have a material impact on its financial statements, the ultimate outcome of these matters cannot be determined at this time.

On January 18, 2013, the Company filed its annual PEP filing for 2013, which indicated a rate increase of 1.990%, or $15.8 million, annually.

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

Environmental Compliance Overview Plan

In November 2011, the Company filed a request to establish a regulatory asset to defer certain plant retirement costs if such costs are incurred. This request was made to minimize the potential rate impact to customers arising from pending and final environmental regulations which may require the premature retirement of some generating units. These environmental rules and regulations are continuously being monitored by the Company and all options are being evaluated. In December 2011, an order was issued by the Mississippi PSC authorizing the Company to defer all plant retirement related costs resulting from compliance with environmental regulations as a regulatory asset for future recovery.

On February 14, 2012, the Company submitted its 2012 ECO Plan filing which proposed a 0.3% increase in annual revenues for the Company. In compliance with the certificate of public convenience and necessity (CPCN) to construct a scrubber on Plant Daniel Units 1 and 2, the Company revised the 2012 ECO Plan filing to exclude scrubber expenditures from rate base, which resulted in a 0.16% decrease in annual revenues. On June 22, 2012, the 2012 ECO Plan filing, including the proposed rate decrease, was approved by the Mississippi PSC, effective on June 29, 2012.

On April 3, 2012, the Mississippi PSC approved the Company's request for a CPCN to construct a scrubber on Plant Daniel Units 1 and 2. On May 3, 2012, the Sierra Club filed a notice of appeal of the order with the Chancery Court of Harrison County, Mississippi (Chancery Court). These units are jointly owned by the Company and Gulf Power, with 50% ownership each. The estimated total cost of the project is approximately $660 million, with the Company's portion being $330 million, excluding AFUDC. The project is scheduled for completion in December 2015. The Company's portion of the cost is expected to be recovered through the ECO Plan. As of December 31, 2012, total

project expenditures were $146.6 million, with the Company's portion being $73.3 million.
On February 12, 2013, the Company submitted its 2013 ECO Plan filing, which proposed no change in rates.
The ultimate outcome of these matters cannot be determined at this time.
Certificated New Plant
See "Integrated Coal Gasification Combined Cycle" for information on certificated new plant and the Company's cost recovery plans.

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Fuel Cost Recovery
The Company establishes, annually, a retail fuel cost recovery factor that is approved by the Mississippi PSC. On January 18, 2013, in compliance with the Company's filing requirement, the Company requested an annual adjustment of the retail fuel cost recovery factor in an amount equal to a decrease of 4.7% of total 2012 retail revenue. At December 31, 2012, the amount of over recovered retail fuel costs included in the balance sheets was $56.6 million compared to $42.4 million at December 31, 2011. The Company also has a wholesale Municipal and Rural Associations (MRA) and a Market Based (MB) fuel cost recovery factor. Effective January 1, 2013, the wholesale MRA fuel rate decreased resulting in an annual decrease in an amount equal to 3.3% of total 2012 MRA revenue. Effective February 1, 2013, the wholesale MB fuel rate decreased, resulting in an annual decrease in an amount equal to 5.5% of total 2012 MB revenue. At December 31, 2012, the amount of over recovered wholesale MRA and MB fuel costs included in the balance sheets was $19.0 million and $2.1 million compared to $14.3 million and $2.2 million, respectively, at December 31, 2011. In addition, at December 31, 2012, the amount of over recovered MRA emissions allowance cost included in the balance sheets was $0.4 million compared to $1.7 million at December 31, 2011. The Company's operating revenues are adjusted for differences in actual recoverable fuel cost and amounts billed in accordance with the currently approved cost recovery rate. Accordingly, changes in the billing factor have no significant effect on the Company's revenues or net income, but will affect annual cash flow.
In March 2011, a portion of the Company's territorial wholesale loads that was formerly served under the MB tariff terminated service. Beginning in April 2011, a new power purchase agreement (PPA) went into effect to cover these MB customers as non-territorial load. In June 2011, the Company and South Mississippi Electric Power Association (SMEPA) reached an agreement to allocate $3.7 million of the over recovered fuel balance at March 31, 2011 to the PPA. This amount was subsequently refunded to SMEPA in June 2011.
The Mississippi PSC engaged an independent professional audit firm to conduct an audit of the Company's fuel-related expenditures included in the retail fuel adjustment clause and ECM. The 2012 audit of fuel-related expenditures began in the second quarter 2012 and was completed in the fourth quarter 2012 with no audit findings.
System Restoration Rider
The Company is required to make annual SRR filings to review charges to the property damage reserve and to determine the revenue requirement associated with property damage. The purpose of the SRR is to provide for recovery of costs associated with property damage (including certain property insurance and the costs of self insurance) and to facilitate the Mississippi PSC's review of these costs. The Mississippi PSC periodically agrees on SRR revenue levels that are developed based on historical data, expected exposure, type and amount of insurance coverage excluding insurance costs, and other relevant information. The applicable SRR rate level will be adjusted every three years, unless a significant change in circumstances occurs such that the Company and the MPUS or the Mississippi PSC deems that a more frequent change would be appropriate. The Company will submit annual filings setting forth SRR-related revenues, expenses, and investment for the projected filing period, as well as the true-up for the prior period.
In January 2011, the Company submitted its 2011 SRR rate filing with the Mississippi PSC, which proposed that the 2011 SRR rate level remain at zero and the Company be allowed to accrue $3.6 million to the property damage reserve in 2011. On May 5, 2011, the filing was approved by the Mississippi PSC. On February 2, 2012, the Company submitted its 2012 SRR rate filing with the Mississippi PSC, which proposed that the 2012 SRR rate level remain at zero and the Company be allowed to accrue $3.8 million to the property damage reserve in 2012. On April 3, 2012, the filing was approved by the Mississippi PSC. On February 1, 2013, the Company submitted its 2013 SRR rate filing with the Mississippi PSC, which proposed that the 2013 SRR rate level remain at zero and the Company be allowed to accrue $3.2 million to the property damage reserve in 2013. The ultimate outcome of this matter cannot be determined at this time.
Storm Damage Cost Recovery

In August 2012, Hurricane Isaac hit the Gulf Coast of the United States and caused damage within the Company's service area. The estimated total storm restoration costs relating to Hurricane Isaac through December 31, 2012 were $10.5 million. The Company maintains a reserve to cover the cost of damage from major storms to its transmission and distribution facilities and generally the cost of uninsured damage to its generation facilities and other property. At December 31, 2012, the balance in the storm reserve was $58.8 million.

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Integrated Coal Gasification Combined Cycle
General
The Company is constructing the Kemper IGCC which will utilize an IGCC technology with an output capacity of 582 MWs. The Kemper IGCC will use as fuel locally mined lignite (an abundant, lower heating value coal) from a mine owned by the Company and situated adjacent to the Kemper IGCC. In connection with the Kemper IGCC, the Company also plans to construct and operate approximately 61 miles of CO_2 pipeline infrastructure. The Kemper IGCC is scheduled to be placed in-service in May 2014.
In 2010, the Mississippi PSC issued a CPCN authorizing the acquisition, construction, and operation of the Kemper IGCC (2010 MPSC Order). The Sierra Club filed an appeal of the Mississippi PSC's issuance of the CPCN and, on March 15, 2012, the Mississippi Supreme Court reversed the decision of the Chancery Court of Harrison County, Mississippi (Chancery Court) upholding the 2010 MPSC Order and remanded the matter to the Mississippi PSC. The Mississippi Supreme Court concluded that the 2010 MPSC Order did not cite in sufficient detail substantial evidence upon which the Mississippi Supreme Court could determine the basis for the findings of the Mississippi PSC granting the CPCN. On March 30, 2012, the Mississippi PSC issued a temporary authorization which allowed the Company to continue construction and, on April 24, 2012, issued a detailed order (2012 MPSC Order) confirming the CPCN for the Kemper IGCC. On April 26, 2012, the Sierra Club appealed the 2012 MPSC Order to the Chancery Court. On December 17, 2012, the Chancery Court affirmed the 2012 MPSC Order which confirmed the issuance of the CPCN for the Kemper IGCC. On January 8, 2013, the Sierra Club filed an appeal of the Chancery Court's ruling with the Mississippi Supreme Court.
The certificated cost estimate of the Kemper IGCC included in the 2012 MPSC Order was $2.4 billion, net of $245.3 million of grants awarded to the project by the DOE under the CCPI2 and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, and financing costs related to the Kemper IGCC. The 2012 MPSC 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. Exemptions from the cost cap included in the 2012 MPSC Order included the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, financing costs, and certain general exceptions, including change of law, force majeure, and beneficial capital (which exists when the Company 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).
The Company's current cost estimate for the Kemper IGCC (net of the $245.3 million CCPI2 grant, and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, financing costs, and certain general exceptions as contemplated in the 2012 MPSC Order and the settlement agreement between the Company and the Mississippi PSC entered into on January 24, 2013 (Settlement Agreement) that must be specifically approved by the Mississippi PSC) is approximately $2.88 billion. The Mississippi PSC and the MPUS have engaged their independent monitors to assess the current cost estimates and schedule projections for the Kemper IGCC. These consultants have issued reports with their own opinions as to the likelihood that costs for the Kemper IGCC will remain at or under the $2.88 billion cost cap and as to the expected in-service date. While the Company continues to believe its cost estimate and schedule projection remain appropriate based on the current status of the project, it is possible that the Company could experience further cost increases and/or schedule delays with respect to the Kemper IGCC. Certain factors have caused and may continue to cause the costs for the Kemper IGCC to increase and/or schedule delays to occur including, but not limited to, costs and productivity of labor, adverse weather conditions, shortages and inconsistent quality of equipment, materials and labor, contractor or supplier delay or non-performance under construction or other agreements, and unforeseen engineering problems. To the extent it becomes probable that costs beyond any permitted exceptions to the cost cap will exceed $2.88 billion or it becomes probable that the Mississippi PSC will disallow a portion of the costs relating to the Kemper IGCC, including certain general exceptions as contemplated in the 2012 MPSC Order and the Settlement Agreement, charges to expense may occur and these charges could be material. See

"Cost Recovery Plans" below for additional information relating to the Settlement Agreement that defines the process for resolving matters regarding cost recovery related to the Kemper IGCC.

As of December 31, 2012, the Company had spent a total of $2.51 billion on the Kemper IGCC, including the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, and other deferred costs. Of this total, $2.47 billion was included in CWIP (which is net of $245.3 million of CCPI2 grant funds), $34.9 million was recorded in other regulatory assets, $3.8 million was recorded in other deferred charges and assets, and $1.0 million was previously expensed. Consistent with the treatment of non-capital costs incurred during the pre-construction period, the Mississippi PSC granted the Company the authority to defer all non-capital Kemper IGCC-related costs to a regulatory asset during the construction period. This includes deferred costs associated with the generation resource planning, evaluation, and screening activities. The amortization period for the regulatory asset will be determined by the Mississippi PSC at a later date.

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In addition, the Company 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.
The 2012 MPSC Order established periodic prudence reviews during the annual CWIP review process. Of the total costs of $51 million incurred through March 2009, $46 million has been reviewed and deemed prudent by the Mississippi PSC. Due to the decision of the Mississippi PSC to deny the Certificated New Plant-A (CNP-A) rate filing and a 2012 rate request related to the Kemper IGCC described below, prudence reviews for the construction costs of the Kemper IGCC incurred after March 2009 have not been made. The Settlement Agreement provides for completion of all prudence reviews within six months of the date the Kemper IGCC is placed in service. See "Cost Recovery Plans" herein for additional information.
The ultimate outcome of these matters, including the determinations of prudency and the specific manner of recovery of prudently-incurred costs relating to the Kemper IGCC, is subject to further regulatory actions and cannot be determined at this time.
Cost Recovery Plans
The 2012 MPSC Order included provisions relating to both the Company's recovery of financing costs during the course of construction of the Kemper IGCC and the Company's recovery of costs following the date the Kemper IGCC is placed in service. In the 2012 MPSC Order, the Mississippi PSC approved financing cost recovery on CWIP balances not to exceed the $2.4 billion certificated cost estimate for the Kemper IGCC. The 2012 MPSC Order provided for the accrual of AFUDC in 2010 and 2011 and for the current recovery of financing costs on 100% of CWIP in 2012, 2013, and through May 1, 2014 (provided that the amount of financing cost recovery allowed is to be reduced by the amount of certain state and federal government construction cost incentives received by the Company and must be justified by a showing that such recovery will benefit customers over the life of the Kemper IGCC). With respect to recovery of costs following the in-service date of the Kemper IGCC, the 2012 MPSC Order provided for the establishment of operational cost and revenue parameters based upon assumptions in the Company's petition for the CPCN.
On June 1, 2012, the MPUS signed a joint stipulation with the Company to establish a proposed rate schedule detailing CNP-A and, on June 14, 2012, the Company submitted to the Mississippi PSC a filing to establish the new CNP-A rate schedule and a stipulated rate increase based upon the revenue request of between $55.3 million and $58.6 million to recover financing costs over the remainder of 2012. On June 22, 2012, the Mississippi PSC denied the proposed CNP-A rate schedule and the 2012 rate recovery filings submitted by the Company, 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.
On July 9, 2012, the Company appealed the Mississippi PSC's June 22, 2012 decision to the Mississippi Supreme Court and requested interim rates under bond of $55.3 million. On July 31, 2012, the Mississippi Supreme Court denied the Company's request for interim rates under bond until the Mississippi Supreme Court decides the Company's appeal of the Mississippi PSC's June 22, 2012 decision.
On January 24, 2013, the Company and the Mississippi PSC entered into the Settlement Agreement that (1) establishes the process for resolving matters regarding cost recovery related to the Kemper IGCC for the purpose of mitigating risks to the Company and its customers and expediting the regulatory process associated with future rate filings required under the Settlement Agreement and (2) resolves the Company's CNP-A rate appeal before the Mississippi Supreme Court.
On February 12, 2013, the Mississippi Supreme Court granted the Company and the Mississippi PSC's joint filing for dismissal of the Company's appeal of the Mississippi PSC's June 22, 2012 decision.
Under the terms of the Settlement Agreement, the Company and the Mississippi PSC will follow certain agreed-upon regulatory procedures and schedules for resolving the cost recovery matters related to the Kemper IGCC. These procedures and schedules include the following: (1) the Company's filing within 30 days of the Settlement Agreement

of a new request to increase rates in 2013 in an amount not to exceed a $172 million annual revenue requirement, based upon projected investment as of December 31, 2013, to be recorded to a regulatory liability to be used to mitigate rate impacts when the Kemper IGCC is placed in service (which filing for $172 million was made on January 25, 2013); (2) the Mississippi PSC's decision on that matter within 50 days of the Company's request; (3) the Company's collaboration with the MPUS to file with the Mississippi PSC within three months of the Settlement Agreement 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 (which filing was made on February 26, 2013 as described below); (4) the Mississippi PSC's decision on the rate recovery plan within four months of that filing; (5) the Company's agreement to limit the portion of prudently-incurred Kemper IGCC costs to be included in rate base to the $2.4 billion certificated cost estimate, plus costs related to the lignite mine and CO_2 pipeline as well as any other costs permitted or determined to be excluded from the cost cap, provided that this limitation will not prevent the Company from securing alternate financing to recover any prudently-incurred Kemper IGCC costs, including financing costs and plant costs above the $2.4 billion certificated cost estimate, not otherwise recovered in any Mississippi PSC rate proceeding contemplated by the Settlement Agreement; and (6) the Mississippi PSC's completion of its prudence review of the Kemper IGCC costs incurred through 2012 within six months of the Settlement Agreement, an additional prudence review upon considering the seven-year rate plan for costs incurred through the most recent reporting period, and a final prudence review of the remaining project costs within six months of the Kemper IGCC's in-service date.

Legislation to authorize a multi-year rate plan and legislation to provide for alternate financing through securitization was passed in the Mississippi legislature and was signed by the Governor on February 26, 2013. The Company contemplates using securitization as provided in the legislation as its form of alternate financing for prudently-incurred Kemper IGCC costs, including financing costs and plant costs above the $2.4 billion certificated cost estimate, not otherwise recovered in any Mississippi PSC rate proceeding contemplated by the Settlement Agreement.

On February 26, 2013, the Company, in compliance with the Settlement Agreement, filed with the Mississippi PSC a rate recovery plan for the Kemper IGCC for 2014 through 2020, the first seven years of operation of the Kemper IGCC. The rate recovery plan proposes recovery of an annual revenue requirement of approximately $150 million of Kemper IGCC-related operational costs and rate base amounts, including plant costs equal to the $2.4 billion certificated cost estimate. Approval of the Company's request to increase rates in 2013 to mitigate the rate impacts of the Kemper IGCC filed on January 25, 2013 is integral to the rate recovery plan as the proposed filing contemplates amortization of the regulatory liability to be used to mitigate rate impacts from 2014 through 2020, based on a fixed amortization schedule that requires approval by the Mississippi PSC. Under the rate recovery plan filing, the Company proposes annual recovery to remain the same from 2014 through 2020 and while it is the intent of the Company for the actual revenue requirement to equal the proposed revenue requirement for certain items, the Company proposes that the annual differences for those items through 2020 will be deferred, subject to accrual of carrying costs, and the cumulative balance will be reviewed at the end of the term of the Settlement Agreement by the Mississippi PSC for determination of the manner of recovery. The Company proposes to secure recovery of prudently-incurred Kemper IGCC costs, including financing costs and plant costs above the $2.4 billion certificated cost estimate, not otherwise recovered in any Mississippi PSC rate proceeding contemplated by the Settlement Agreement to be provided for with alternate financing through securitization. The rate recovery necessary to recover the annual costs of securitization is proposed to be filed and begin after the Kemper IGCC is placed in service.

Under the terms of the Settlement Agreement, the Company has the right to terminate the Settlement Agreement if certain conditions, including the passage of multi-year rate plan legislation that is contemplated under the Settlement Agreement, are not met, if the Company 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.

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

Tax Incentives

The Internal Revenue Service (IRS) has allocated $133 million (Phase I) and $279 million (Phase II) of Internal Revenue Code Section 48A tax credits to the Company in connection with the Kemper IGCC. The Company's utilization of Phase I and Phase II credits is dependent upon meeting the IRS certification requirements, including an in-service date no later than May 11, 2014 for the Phase I credits and April 19, 2016 for the Phase II credits. In order to remain eligible for the Phase II credits, the Company plans to capture and sequester (via enhanced oil recovery) at least 65% of the CO_2 produced by the Kemper IGCC during operations in accordance with the rules for Section 48A investment tax credits. Through December 31, 2012, the Company received or accrued tax benefits totaling $361.6 million for these tax credits, which will be amortized as a reduction to depreciation and amortization over the life of the Kemper IGCC. As a result of bonus tax depreciation on certain assets placed, or to be placed, in service in 2012 and 2013, and the subsequent reduction in federal taxable income, the Company estimates that it will not be able to utilize $170.9 million of these tax credits until after 2013. IRS guidelines allow these unused tax credits to be carried forward for 20 years, expiring at the end of 2031, if not utilized before then. On October 15, 2012, the Company filed an application with the DOE for certification of the Kemper IGCC for additional tax credits under the Internal Revenue Code Section 48A (Phase III). A portion of the tax credits realized by the Company may be subject to recapture upon successful completion of SMEPA's purchase of an undivided interest in the Kemper IGCC as described below. In addition, all or a portion of the tax credits will be subject to recapture if the Company fails to satisfy the in-service date requirements and carbon capture requirements described above. See Note 5 under "Current and Deferred Income Taxes" for additional information.

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 50% bonus depreciation for property to be placed in service in 2013 (and for certain long-

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term production-period projects to be placed in service in 2014), which is expected to apply to the Kemper IGCC. The ultimate outcome of these matters cannot be determined at this time.

Lignite Mine and CO_2 Pipeline Facilities

In conjunction with the Kemper IGCC, the Company will own the 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 is scheduled to be placed in-service in June 2013. The estimated capital cost of the mine is approximately $245 million, of which $163.3 million has been incurred through December 31, 2012.

In 2010, the Company 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. Because Liberty Fuels conducts all of its activities on behalf of the Company, Liberty Fuels qualifies as a VIE for which the Company is the primary beneficiary. 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 the Company has a contractual obligation to fund all reclamation activities. Consistent with the requirements of consolidation accounting, Liberty Fuels is consolidated in the financial statements of the Company and accordingly the asset retirement cost and the ARO have been recorded in the Company's financial statements. In addition to the obligation to fund the reclamation activities, the Company currently provides working capital support to Liberty Fuels through cash advances for capital purchases, payroll, and other operating expenses.

In addition, the Company will acquire, construct, and operate the CO_2 pipeline for the planned transport of captured CO_2 for use in enhanced oil recovery. The Company 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 estimated capital cost of the CO_2 pipeline facilities is approximately $132 million, of which $78.4 million has been incurred through December 31, 2012.

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

Proposed Sale of Undivided Interest to SMEPA

In 2010, the Company and SMEPA entered into an asset purchase agreement whereby SMEPA agreed to purchase a 17.5% undivided interest in the Kemper IGCC. On February 28, 2012, the Mississippi PSC approved the sale and transfer of 17.5% of the Kemper IGCC to SMEPA. On June 29, 2012, the Company and SMEPA signed an amendment to the asset purchase agreement whereby SMEPA extended its option to purchase until December 31, 2012 and 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 December 31, 2012, the Company and SMEPA agreed to extend SMEPA's option to purchase through December 31, 2013.

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. On September 27, 2012, SMEPA received a conditional loan commitment from Rural Utilities Service to provide funding for SMEPA's undivided interest in the Kemper IGCC.

On March 6, 2012, the Company received a $150 million interest-bearing refundable deposit from SMEPA to be applied to the purchase. While the expectation is that the amount will be applied to the purchase price at closing, the Company would be required to refund the deposit 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 the Company 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 Services, 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 deposit has been presented as a current liability in the Company's balance sheet herein and as financing proceeds in the Company's statement of cash flows herein.

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

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

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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 will depend on the outcome of any legal challenges and cannot be determined at this time. See "Cost Recovery Plans" herein for additional information regarding certain legislation related to the Kemper IGCC.

4. JOINT OWNERSHIP AGREEMENTS
The Company and Alabama Power own, as tenants in common, Units 1 and 2 (total capacity of 500 MWs) at Greene County Steam Plant, which is located in Alabama and operated by Alabama Power. Additionally, the Company and Gulf Power, own as tenants in common, Units 1 and 2 (total capacity of 1,000 MWs) at Plant Daniel, which is located in Mississippi and operated by the Company.
At December 31, 2012, the Company's percentage ownership and investment in these jointly-owned facilities in commercial operation were as follows:

Generating Plant	Percent Ownership	Plant in Service	Accumulated Depreciation	Construction Work in Progress
		(in thousands)		
Greene County Units 1 and 2	40 %	$89,474	$45,402	$4,386
Daniel Units 1 and 2	50 %	$293,451	$147,833	$73,534

The Company's proportionate share of plant operating expenses is included in the statements of income and the Company is responsible for providing its own financing.
See Note 3 under "Retail Regulatory Matters – Environmental Compliance Overview Plan" 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 and Mississippi. Under a joint consolidated income tax allocation agreement, each subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more current expense than would be paid if it filed a separate income tax return. In accordance with IRS regulations, each company is jointly and severally liable for the federal tax liability.

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Current and Deferred Income Taxes
Details of income tax provisions are as follows:

	2012	2011	2010
	(in thousands)		
Federal —			
Current	$1,212	$(27,099)	$5,399
Deferred	42,929	65,206	35,367
	44,141	38,107	40,766
State —			
Current	1,656	(2,473)	3,319
Deferred	4,594	6,559	2,190
	6,250	4,086	5,509
Total	$50,391	$42,193	$46,275

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

	2012	2011
	(in thousands)	
Deferred tax liabilities —		
Accelerated depreciation	$385,899	$356,857
Property basis differences	72,451	48,268
Energy cost management clause under recovered	9,492	7,880
Regulatory assets associated with asset retirement obligations	16,851	7,557
Pensions and other benefits	33,756	18,283
Regulatory assets associated with employee benefit obligations	68,717	52,410
Regulatory assets associated with the Kemper IGCC	10,492	4,618
Long-term service agreement	—	5,231
Rate differential	27,270	8,400
Other	33,886	23,802
Total	658,814	533,306
Deferred tax assets —		
Federal effect of state deferred taxes	9,097	10,899
Fuel clause over recovered	38,955	30,050
Other property basis differences	980	2,918
Pension and other benefits	87,416	70,255
Property insurance	23,171	25,349
Premium on long-term debt	26,778	29,820
Unbilled fuel	11,642	14,951
Long-term service agreement	5,544	—
Asset retirement obligations	16,851	7,557
Interest rate hedges	5,644	5,763
Investment tax credit carryforward	170,938	77,400
Other	22,820	21,571
Total	419,836	296,533
Total deferred tax liabilities, net	238,978	236,773
Portion included in (accrued) prepaid income taxes, net	35,815	33,624
Accumulated deferred income taxes	$274,793	$270,397

At December 31, 2012, the tax-related regulatory assets were $73.0 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, 2012, the tax-related regulatory liabilities were $11.2 million. These liabilities are primarily attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and to unamortized investment tax credits.

In accordance with regulatory requirements, deferred investment tax credits 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 for non-Kemper IGCC related deferred investment tax credits amortized in this manner amounted to $1.2 million, $1.3 million, and $1.3 million for 2012, 2011, and 2010, respectively. At December 31, 2012, all non-Kemper IGCC investment tax credits available to reduce federal income taxes payable had been utilized.

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In 2010, the Company began recognizing investment tax credits associated with the construction expenditures related to the Kemper IGCC. At December 31, 2012, the Company had $361.6 million in unamortized investment tax credits associated with the Kemper IGCC, which will be amortized over the life of the Kemper IGCC once placed in service. As a result of 100% bonus tax depreciation on certain assets placed, or to be placed, in service in 2012 and 2013, and the subsequent reduction in federal taxable income, the Company estimates that it will not be able to utilize $170.9 million of these tax credits until after 2013. IRS guidelines allow the resultant unused credits to be carried forward for 20 years expiring at the end of 2031, if not utilized before then.

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 include100% 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 to be placed in service in 2013).

Effective Tax Rate

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

	2012		2011		2010	
Federal statutory rate	35.0	%	35.0	%	35.0	%
State income tax, net of federal deduction	2.0		1.9		2.8	
Non-deductible book depreciation	0.2		0.3		0.3	
Medicare subsidy	(0.1	)	(0.1	)	(0.2	)
AFUDC-equity	(11.3	)	(6.3	)	(1.0	)
Other	(0.7	)	(0.2	)	(0.8	)
Effective income tax rate	25.1	%	30.6	%	36.1	%

The Company's 2012 effective tax rate decreased from 2011 primarily due to the increase in non-taxable AFUDC equity related to increased construction expenditures.

Unrecognized Tax Benefits

For 2012, the total amount of unrecognized tax benefits increased by $0.8 million, resulting in a balance of $5.8 million as of December 31, 2012.

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

	2012		2011		2010	
	(in thousands)					
Unrecognized tax benefits at beginning of year	$4,964		$4,288		$3,026	
Tax positions from current periods	1,186		1,486		868	
Tax positions from prior periods	(26	)	(810	)	611	
Reductions due to expired statute of limitations	—		—		(217	)
Settlements with taxing authorities	(369	)	—		—	
Balance at end of year	$5,755		$4,964		$4,288	

The change in tax positions from current periods for 2012 relates primarily to the tax accounting method change for repairs-generation assets and State of Mississippi tax credits. The tax positions decrease from prior periods for 2012 relates to the uncertain tax position for the tax accounting method change for repairs-transmission and distribution assets. See "Tax Method of Accounting for Repairs" below for additional information.

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The impact on the Company's effective tax rate, if recognized, was as follows:

	2012	2011	2010
	(in thousands)		
Tax positions impacting the effective tax rate	$3,656	$4,144	$3,058
Tax positions not impacting the effective tax rate	2,099	820	1,230
Balance of unrecognized tax benefits	$5,755	$4,964	$4,288

The tax positions impacting the effective tax rate for 2012 primarily relate to the State of Mississippi Investment Tax Credit. 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:

	2012	2011	2010
	(in thousands)		
Interest accrued at beginning of year	$680	$413	$230
Interest accrued during the year	92	267	183
Balance at end of year	$772	$680	$413

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 associated with a majority of the Company's unrecognized tax positions will significantly increase or decrease within 12 months. The resolution of the tax accounting method change for repairs-generation assets, as well as the conclusion or settlement of 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 audited and closed all of Southern Company's consolidated federal income tax returns prior to 2009 and has settled its audits of Southern Company's consolidated federal income tax returns for 2009 and 2010, in principle, pending final approval. Additionally, the IRS has audited and closed Southern Company's 2011 consolidated federal income tax return. For tax years 2010 through 2013, Southern Company is a participant in the Compliance Assurance Process of the IRS. The audits for the Company's state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2007.

Tax Method of Accounting for Repairs

Southern Company submitted a tax accounting method change related to the deductibility of repair costs associated with its subsidiaries' generation, transmission, and distribution systems effective for the 2009 consolidated federal income tax return in 2010. In August 2011, the IRS issued a revenue procedure, which provides a safe harbor method of accounting that taxpayers may use to determine eligible repair costs for transmission and distribution property. The IRS continues to work with the utility industry in an effort to define eligible repair costs for generation assets in a consistent manner for all utilities. 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. The utility industry anticipates more detailed guidance concerning these regulations. Due to the uncertainty regarding the ultimate resolution of the repair costs for generation assets, an unrecognized tax position has been recorded for the tax accounting method change for repairs-generation assets. The ultimate outcome of this matter cannot be determined at this time; however, it is not expected to materially impact net income.

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6. FINANCING
Bank Term Loans
In March 2012, the Company paid at maturity a $75 million aggregate principal amount variable rate bank note bearing interest at a rate based on one-month London Interbank Offered Rate (LIBOR).
In September 2012, the Company paid at maturity a $40 million aggregate principal amount variable rate bank note bearing interest at a rate based on one-month LIBOR.
In November 2012, the Company entered into a 366-day $100 million aggregate principal amount floating rate bank loan that bears interest based on one-month LIBOR. The first advance in the amount of $50 million was made in November 2012. Subsequent to December 31, 2012, the second advance in the amount of $50 million was made. The proceeds of this loan were used solely for working capital and for other general corporate purposes, including the Company's continuous construction program.
At December 31, 2012 and 2011, the Company had $175 million and $240 million of bank loans outstanding, respectively.
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, 2012, the Company was in compliance with its debt limits.
In addition, these bank loans contain cross default provisions that would be triggered if the borrower defaulted on other indebtedness 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. The Company is currently in compliance with all such covenants.
Senior Notes
In March 2012, the Company issued $250.0 million aggregate principal amount of Series 2012A 4.25% Senior Notes due March 15, 2042 and an additional $150.0 million aggregate principal amount of Series 2011A 2.35% Senior Notes due October 15, 2016. The Series 2011A Senior Notes were of the same series of notes that were originally issued in October 2011 in the aggregate principal amount of $150.0 million. Upon completion of this offering, the aggregate principal amount of the outstanding Series 2011A Senior Notes was $300.0 million. The proceeds from the sales of the Series 2012A Senior Notes and the Series 2011A Senior Notes were used to repay a bank term loan in an aggregate principal amount of $75.0 million and for general corporate purposes, including the Company's continuous construction program.
In March 2012, $300.0 million in interest rate swaps were settled, of which $250.0 million related to the Series 2012A Senior Notes at a loss of approximately $13.3 million, which will be amortized to interest expense, in earnings, over 10 years, and $50.0 million related to the Series 2011A Senior Notes at a loss of approximately $2.7 million, which will be amortized to interest expense, in earnings, over 10 years.
In May 2012, the Company redeemed $90.0 million aggregate principal amount of Series E 5-5/8% Senior Notes due May 1, 2033.
In August 2012, the Company issued an additional $200.0 million aggregate principal amount of Series 2012A 4.25% Senior Notes due March 15, 2042. The Series 2012A Senior Notes were of the same series of notes that were originally issued in March 2012 in the aggregate principal amount of $250.0 million. Upon completion of this offering, the aggregate principal amount of the outstanding Series 2012A Senior Notes is $450.0 million. The proceeds from this sale of the Series 2012A Senior Notes were used for general corporate purposes, including the Company's continuous construction program.
At December 31, 2012 and 2011, the Company had $1.1 billion and $630.0 million of senior notes outstanding, respectively. These senior notes are effectively subordinated to all secured debt of the Company. See "Plant Daniel Revenue Bonds" below for additional information regarding the Company's secured indebtedness.
Plant Daniel Revenue Bonds

In October 2011, in connection with the Company's election under its operating lease of Plant Daniel Units 3 and 4 to purchase the assets, the Company assumed the obligations of the lessor related to $270.0 million aggregate principal amount of Mississippi Business Finance Corporation Taxable Revenue Bonds, 7.13% Series 1999A due October 20, 2021, issued for the benefit of the lessor as described in Note 1 under "Purchase of the Plant Daniel Combined Cycle Generating Units" herein. These bonds are secured by Plant Daniel Units 3 and 4 and certain personal property. The bonds were recorded at fair value as of the date of assumption, or $346.1 million, reflecting a premium of $76.1 million.

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Securities Due Within One Year

A summary of scheduled maturities and redemptions of securities due within one year at December 31, 2012 and 2011 was as follows:

	2012	2011
	(in millions)	
Senior notes	$50.0	$—
Bank term loans	175.0	240.0
Revenue bonds	51.5	—
Capitalized leases	—	0.6
Outstanding at December 31	$276.5	$240.6

Maturities through 2017 applicable to total long-term debt are as follows: $276.5 million in 2013, $300.0 million in 2016, and $35.0 million in 2017. There are no scheduled maturities in 2014 and 2015.

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, 2012 and 2011 was $82.7 million.

Other Revenue Bonds

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

In August 2012, the Mississippi Business Finance Corporation (MBFC) entered into an agreement to issue up to $42.5 million aggregate principal amount of MBFC Taxable Revenue Bonds, Series 2012A (Mississippi Power Company Project), up to $21.25 million aggregate principal amount of MBFC Taxable Revenue Bonds, Series 2012B (Mississippi Power Company Project), and up to $21.25 million aggregate principal amount of MBFC Taxable Revenue Bonds, Series 2012C (Mississippi Power Company Project) for the benefit of the Company. During 2012, the MBFC issued $8.97 million aggregate principal amount of MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2012A, $21.25 million aggregate principal amount of MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2012B, and $21.25 million aggregate principal amount of MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2012C for the benefit of the Company. The proceeds were used to reimburse the Company 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 2012A bonds will be used for this same purpose.

The Company had $50.0 million of such obligations outstanding related to tax-exempt revenue bonds at December 31, 2012 and 2011, and $51.5 million of such obligations related to taxable revenue bonds outstanding at December 31, 2012. Such amounts are reflected in the statements of capitalization as long-term senior notes and debt.

Other Obligations

In March 2012, the Company received a $150.0 million interest-bearing refundable deposit from SMEPA to be applied to the sale price for the pending sale of an undivided interest in the Kemper IGCC. Until the acquisition is closed, the deposit bears interest at the Company's AFUDC rate adjusted for income taxes, which was 9.967% per annum at December 31, 2012, and is 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 the Company 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.

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Assets Subject to Lien
The revenue bonds assumed in conjunction with the purchase of Plant Daniel Units 3 and 4 are secured by Plant Daniel Units 3 and 4 and certain personal property. See Note 1 under "Purchase of the Plant Daniel Combined Cycle Generating Units" and "Plant Daniel Revenue Bonds" for additional information. There are no agreements or other arrangements among the Southern Company system companies under which the assets of one company have been pledged or otherwise made available to satisfy the obligations of Southern Company or another of its other subsidiaries.
Outstanding Classes of Capital Stock
The Company currently has preferred stock (including depositary shares which represent one-fourth of a share of preferred stock) and common stock authorized and outstanding. The preferred stock of the Company contains a feature that allows the holders to elect a majority of the Company's board of directors if dividends are not paid for four consecutive quarters. Because such a potential redemption-triggering event is not solely within the control of the Company, this preferred stock is presented as "Cumulative Redeemable Preferred Stock" in a manner consistent with temporary equity under applicable accounting standards. The Company's preferred stock and depositary preferred stock, without preference between classes, rank senior to the Company's common stock with respect to payment of dividends and voluntary or involuntary dissolution. The preferred stock and depositary preferred stock is subject to redemption at the option of the Company at a redemption price equal to 100% of the liquidation amount of the stock.
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, 2012, committed credit arrangements with banks were as follows:

Expires[(a)]				Executable Term-Loans		Due Within One Year	
2013	2014	Total	Unused	One Year	Two Years	Term Out	No Term Out
(in millions)							
$135	$165	$300	$300	$25	$40	$65	$70

(a) No credit arrangements expire after 2014.
The Company expects to renew its credit arrangements, as needed, prior to expiration.
Most of these credit arrangements require payment of commitment fees based on the unused portions of the commitments or to maintain compensating balances with the banks. Commitment fees average less than 1/4 of 1% for the Company. Compensating balances are not legally restricted from withdrawal.
Most of these credit arrangements contain covenants that limit the Company's debt levels to 65% of total capitalization, as defined in the agreements. For purposes of these definitions, debt excludes certain hybrid securities. In addition, the credit arrangements typically contain cross default provisions that are restricted to the indebtedness of the Company. The Company is currently in compliance with all such covenants. None of the arrangements contain material adverse change clauses at the time of borrowing.
The Company's unused credit arrangements 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, 2012 was $40.1 million.
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.
At December 31, 2012 and 2011, there was no short-term debt outstanding.

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7. COMMITMENTS
Fuel and Purchased Power Agreements
To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement of fossil fuel which are not recognized on the balance sheets. In 2012, 2011, and 2010, the Company incurred fuel expense of $411.2 million, $490.4 million, and $501.8 million, respectively, the majority of which was purchased under long-term commitments. The Company expects that a substantial amount of its future fuel needs will continue to be purchased under long-term commitments.
Coal commitments include a management fee of $38.1 million over the term of the executed 40-year management contract with Liberty Fuels beginning in 2014 related to the Kemper IGCC. Additional commitments for fuel will be required to supply the Company's future needs.
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. The credit rating of Southern Power is currently below that of the traditional operating companies. 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 operating lease agreements with various terms and expiration dates. Total rent expense was $11.1 million, $32.6 million, and $38.6 million for 2012, 2011, and 2010 respectively, which includes the Plant Daniel Units 3 and 4 operating lease that ended October 20, 2011.
The Company and Gulf Power have jointly entered into operating lease agreements for aluminum railcars for the transportation of coal at Plant Daniel. The Company has the option to purchase the railcars at the greater of lease termination value or fair market value, or to renew the leases at the end of the lease term. In early 2011, one operating lease expired and the Company elected not to exercise the option to purchase. The remaining operating lease has 229 aluminum railcars. The Company and Gulf Power also have separate lease agreements for other railcars that do not contain a purchase option.
The Company's share (50%) of the leases, charged to fuel stock and recovered through the fuel cost recovery clause, was $3.6 million in 2012, $2.6 million in 2011, and $3.5 million in 2010. The Company's annual railcar lease payments for 2013 through 2017 will average approximately $1.6 million.
In addition to railcar leases, the Company has other operating leases for fuel handling equipment at Plants Daniel and Watson and operating leases for barges and tow/shift boats for the transport of coal at Plant Watson. The Company's share (50% at Plant Daniel and 100% at Plant Watson) of the leases for fuel handling was charged to fuel handling expense in the amount of $0.2 million in 2012, $0.4 million in 2011, and $0.7 million in 2010. The Company's annual lease payments for 2013 through 2014 will average approximately $0.2 million for fuel handling equipment. The Company charged to fuel stock and recovered through fuel cost recovery the barge transportation leases in the amount of $7.3 million in 2012, $7.5 million in 2011, and $8.4 million in 2010 related to barges and tow/shift boats. The Company's annual lease payments for 2013 through 2014 with respect to these barge transportation leases will average approximately $8.2 million.
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, 2012, there were 241 current and former employees of the Company participating in the stock option program and there were 39 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. For certain stock option awards, a change in control will provide accelerated vesting.

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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	2012	2011	2010
Expected volatility	17.7%	17.5%	17.4%
Expected term (in years)	5.0	5.0	5.0
Interest rate	0.9%	2.3%	2.4%
Dividend yield	4.2%	4.8%	5.6%
Weighted average grant-date fair value	$3.39	$3.23	$2.23

The Company's activity in the stock option program for 2012 is summarized below:

	Shares Subject to Option	Weighted Average Exercise Price
Outstanding at December 31, 2011	1,569,728	$33.59
Granted	278,709	44.46
Exercised	(474,871)	31.98
Cancelled	—	—
Outstanding at December 31, 2012	1,373,566	$36.34
Exercisable at December 31, 2012	864,634	$33.96

The number of stock options vested, and expected to vest in the future, as of December 31, 2012 was not significantly different from the number of stock options outstanding at December 31, 2012 as stated above. As of December 31, 2012, 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 $9.3 million and $7.7 million, respectively.
As of December 31, 2012, there was $0.3 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, 2012, 2011, and 2010, total compensation cost for stock option awards recognized in income was $0.9 million, $0.8 million, and $0.8 million, respectively, with the related tax benefit also recognized in income of $0.3 million, $0.3 million, and $0.3 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, 2012, 2011, and 2010 was $4.9 million, $4.2 million, and $2.7 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $1.9 million, $1.6 million, and $1.0 million for the years ended December 31, 2012, 2011, and 2010, 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

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(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	2012	2011	2010
Expected volatility	16.0%	19.2%	20.7%
Expected term (in years)	3.0	3.0	3.0
Interest rate	0.4%	1.4%	1.4%
Annualized dividend rate	$1.89	$1.82	$1.75
Weighted average grant-date fair value	$41.99	$35.97	$30.13

Total unvested performance share units outstanding as of December 31, 2011 were 70,830. During 2012, 33,077 performance share units were granted, 32,208 performance share units were vested, and 3,213 performance share units were forfeited resulting in 68,486 unvested units outstanding at December 31, 2012. In January 2013, the vested performance share award units were converted into 43,481 shares outstanding at a share price of $43.05 for the three-year performance and vesting period ended December 31, 2012.

For the years ended December 31, 2012, 2011, and 2010, total compensation cost for performance share units recognized in income was $1.2 million, $0.7 million, and $0.3 million, respectively, with the related tax benefit also recognized in income of $0.4 million, $0.3 million, and $0.1 million, respectively. As of December 31, 2012, there was $1.4 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. FAIR VALUE MEASUREMENTS

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

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

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

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As of December 31, 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:

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 thousands)			
Assets:				
Energy-related derivatives	$—	$2,519	$—	$2,519
Foreign currency derivatives	—	—	—	—
Cash equivalents	125,600	—	—	125,600
Total	$125,600	$2,519	$—	$128,119
Liabilities:				
Energy-related derivatives	$—	$19,446	$—	$19,446
Interest rate derivatives	—	—	—	—
Foreign currency derivatives	—	37	—	37
Total	$—	$19,483	$—	$19,483

As of December 31, 2011, 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, 2011:	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 thousands)			
Assets:				
Energy-related derivatives	$—	$162	$—	$162
Foreign currency derivatives	—	1,526	—	1,526
Cash equivalents	133,900	—	—	133,900
Total	$133,900	$1,688	$—	$135,588
Liabilities:				
Energy-related derivatives	$—	$51,152	$—	$51,152
Interest rate derivatives	—	15,208	—	15,208
Foreign currency derivatives	—	2,510	—	2,510
Total	$—	$68,870	$—	$68,870

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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 LIBOR interest rates. Interest rate and foreign currency 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. Inputs for foreign currency derivatives are from observable market sources. See Note 10 for additional information on how these derivatives are used.

As of December 31, 2012 and 2011, 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, 2012	(in thousands)			
Cash equivalents:				
Money market funds	$125,600	None	Daily	Not applicable
As of December 31, 2011				
Cash equivalents:				
Money market funds	$133,900	None	Daily	Not applicable

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, 2012 and 2011, other financial instruments for which the carrying amount did not equal fair value were as follows:

	Carrying Amount	Fair Value
	(in thousands)	
Long-term debt:		
2012	$1,840,933	$1,956,799
2011	$1,343,596	$1,426,808

The fair values are determined using primarily Level 2 measurements and are based on quoted market prices for the same or similar issues or on the current rates offered to the Company.

10. DERIVATIVES

The Company is exposed to market risks, primarily commodity price risk and interest rate risk and occasionally foreign currency 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.

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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 Mississippi 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 or heat rate 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 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, 2012, 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:

Gas Net Purchased mmBtu* (in millions)	Longest Hedge Date	Longest Non-Hedge Date
38	2017	—

* mmBtu — million British thermal units

For cash flow hedges, the amounts expected to be reclassified from OCI to revenue and fuel expense for the next 12-month period ending December 31, 2013 are immaterial.
Foreign Currency Derivatives
The Company 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 losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings. Any ineffectiveness is typically recorded directly to earnings, however, the

Company has regulatory approval allowing it to defer any ineffectiveness associated with firm commitments related to the Kemper IGCC to a regulatory asset. During the year ended December 31, 2011, certain fair value hedges were de-designated and subsequently settled in 2012. The ineffectiveness related to the de-designated hedges was recorded as a regulatory asset and was immaterial to the Company. The derivatives employed as hedging instruments are structured to minimize ineffectiveness.

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At December 31, 2012, the following foreign currency derivatives were outstanding:

	Notional Amount	Forward Rate	Hedge Maturity Date	Fair Value Gain (Loss) December 31, 2012
	(in thousands)			(in thousands)
Fair value hedges of firm commitments				
	EUR735	1.3758 Dollars per Euro	March 2014	$(37)

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, 2012, there were no interest rate derivatives outstanding.

For the year ended December 31, 2012, the Company had realized net losses of $16.0 million upon termination of certain interest rate derivatives at the same time the related debt was issued. The effective portion of these losses has been deferred in OCI and is being amortized to interest expense over the life of the original interest rate derivative, reflecting the period in which the forecasted hedged transaction affects earnings.

The estimated pre-tax losses that will be reclassified from OCI to interest expense for the 12-month period ending December 31, 2013 are $1.4 million. The Company has deferred gains and losses that are expected to be amortized into earnings through 2022.

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Derivative Financial Statement Presentation and Amounts
At December 31, 2012 and 2011, the fair value of energy-related derivatives, foreign currency derivatives, and interest rate derivatives was reflected in the balance sheets as follows:

Derivative Category	Asset Derivatives Balance Sheet Location	2012	2011	Liability Derivatives Balance Sheet Location	2012	2011
		(in thousands)			(in thousands)	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	$638	$125	Liabilities from risk management activities	$13,116	$36,455
	Other deferred charges and assets	1,881	37	Other deferred credits and liabilities	6,330	14,697
Total derivatives designated as hedging instruments for regulatory purposes		$2,519	$162		$19,446	$51,152
Derivatives designated as hedging instruments in cash flow and fair value hedges						
Energy-related derivatives:	Other current assets	$—	$—	Liabilities from risk management activities	$—	$—
Interest rate derivatives:	Other current assets	—	—	Liabilities from risk management activities	—	15,208
Foreign currency derivatives:	Other current assets	—	19	Liabilities from risk management activities	—	625
	Other deferred charges and assets	—	—	Other deferred credits and liabilities	37	46
Total derivatives designated as hedging instruments in cash flow and fair value hedges		$—	$19		$37	$15,879
Derivatives not designated as hedging instruments						
Energy-related derivatives:	Other current assets	$—	$—	Liabilities from risk management activities	$—	$—
		—	1,507		—	1,839

Foreign currency derivatives:	Other current assets			Liabilities from risk management activities		
Total derivatives not designated as hedging instruments		$—	$1,507		$—	$1,839
Total		$2,519	$1,688		$19,483	$68,870

All derivative instruments are measured at fair value. See Note 9 for additional information.

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At December 31, 2012 and 2011, 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	2012	2011	Unrealized Gains Balance Sheet Location	2012	2011
		(in thousands)			(in thousands)	
Energy-related derivatives:	Other regulatory assets, current	$(13,116)	$(36,455)	Other regulatory liabilities, current	$638	$125
	Other regulatory assets, deferred	(6,330)	(14,697)	Other regulatory liabilities, deferred	1,881	37
Total energy-related derivative gains (losses)		$(19,446)	$(51,152)		$2,519	$162

For the years ended December 31, 2012, 2011, and 2010, the pre-tax effects of derivatives designated as cash flow hedging instruments on the statements of income were as follows:

Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Recognized in OCI on Derivative (Effective Portion)			Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)			
					Amount		
Derivative Category	2012	2011	2010	Statements of Income Location	2012	2011	2010
	(in thousands)				(in thousands)		
Energy-related derivatives	$—	$(3)	$3	Fuel	$—	$—	$—
Interest rate derivatives	(774)	(14,361)	—	Interest Expense	(1,073)	48	—
Total	$(774)	$(14,364)	$3		$(1,073)	$48	$—

There was no material ineffectiveness recorded in earnings for any period presented.
For the years ended December 31, 2012, 2011, and 2010, the pre-tax effects of energy-related derivatives not designated as hedging instruments on the statements of income were immaterial. For the year ended December 31, 2012, the pre-tax effect of foreign currency derivatives not designated as hedging instruments was recorded as a regulatory asset and was immaterial to the Company.
For the years ended December 31, 2012 and 2011, the pre-tax effects of foreign currency derivatives designated as fair value hedging instruments, which include a pre-tax loss associated with de-designated hedges prior to de-designation, on the Company's statements of income were a $0.6 million gain and $3.6 million loss, respectively. For the year ended December 31, 2010, the pre-tax gain was $3.3 million. These amounts were offset by changes in the fair value of the purchase commitment related to equipment purchases. Therefore, there is no impact on the Company's statements of income.
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, 2012, the fair value of derivative liabilities with contingent features was $2.9 million.
At December 31, 2012, 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 $15.1 million.

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.

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11. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)
Summarized quarterly financial information for 2012 and 2011 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred Stock
	(in thousands)		
March 2012	$228,714	$30,213	$25,255
June 2012	266,084	46,986	35,027
September 2012	305,419	66,151	54,625
December 2012	235,779	31,662	33,200
March 2011	$263,276	$25,151	$14,617
June 2011	286,041	39,056	25,283
September 2011	325,766	53,171	38,019
December 2011	237,794	16,412	16,263

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

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SELECTED FINANCIAL AND OPERATING DATA 2008-2012
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	2012	2011	2010	2009	2008
Operating Revenues (in thousands)	$1,035,996	$1,112,877	$1,143,068	$1,149,421	$1,256,542
Net Income After Dividends on Preferred Stock (in thousands)	$148,107	$94,182	$80,217	$84,967	$85,960
Cash Dividends on Common Stock (in thousands)	$106,800	$75,500	$68,600	$68,500	$68,400
Return on Average Common Equity (percent)	10.41	10.54	11.49	13.12	13.75
Total Assets (in thousands)	$5,451,621	$3,671,842	$2,476,321	$2,072,681	$1,952,695
Gross Property Additions (in thousands)	$1,665,498	$1,205,704	$340,162	$95,573	$139,250
Capitalization (in thousands):					
Common stock equity	$1,797,373	$1,049,217	$737,368	$658,522	$636,451
Redeemable preferred stock	32,780	32,780	32,780	32,780	32,780
Long-term debt	1,564,462	1,103,596	462,032	493,480	370,460
Total (excluding amounts due within one year)	$3,394,615	$2,185,593	$1,232,180	$1,184,782	$1,039,691
Capitalization Ratios (percent):					
Common stock equity	52.9	48.0	59.8	55.6	61.2
Redeemable preferred stock	1.0	1.5	2.7	2.8	3.2
Long-term debt	46.1	50.5	37.5	41.6	35.6
Total (excluding amounts due within one year)	100.0	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	152,265	151,805	151,944	151,375	152,280
Commercial	33,112	33,200	33,121	33,147	33,589
Industrial	472	496	504	513	518
Other	175	175	187	180	183
Total	186,024	185,676	185,756	185,215	186,570
Employees (year-end)	1,281	1,264	1,280	1,285	1,317

SELECTED FINANCIAL AND OPERATING DATA 2008-2012 (continued)
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	2012	2011	2010	2009	2008
Operating Revenues (in thousands):					
Residential	$226,847	$246,510	$256,994	$245,357	$248,693
Commercial	250,860	263,256	266,406	269,423	271,452
Industrial	262,978	275,752	267,588	269,128	258,328
Other	6,768	6,945	6,924	7,041	6,961
Total retail	747,453	792,463	797,912	790,949	785,434
Wholesale — non-affiliates	255,557	273,178	287,917	299,268	353,793
Wholesale — affiliates	16,403	30,417	41,614	44,546	100,928
Total revenues from sales of electricity	1,019,413	1,096,058	1,127,443	1,134,763	1,240,155
Other revenues	16,583	16,819	15,625	14,658	16,387
Total	$1,035,996	$1,112,877	$1,143,068	$1,149,421	$1,256,542
Kilowatt-Hour Sales (in thousands):					
Residential	2,045,999	2,162,419	2,296,157	2,091,825	2,121,389
Commercial	2,915,934	2,870,714	2,921,942	2,851,248	2,856,744
Industrial	4,701,681	4,586,356	4,466,560	4,329,924	4,187,101
Other	38,588	38,684	38,570	38,855	38,886
Total retail	9,702,202	9,658,173	9,723,229	9,311,852	9,204,120
Wholesale — non-affiliates	3,818,773	4,009,637	4,284,289	4,651,606	5,016,655
Wholesale — affiliates	571,908	648,772	774,375	839,372	1,487,083
Total	14,092,883	14,316,582	14,781,893	14,802,830	15,707,858
Average Revenue Per Kilowatt-Hour (cents):					
Residential	11.09	11.40	11.19	11.73	11.72
Commercial	8.60	9.17	9.12	9.45	9.50
Industrial	5.59	6.01	5.99	6.22	6.17
Total retail	7.70	8.21	8.21	8.49	8.53
Wholesale	6.19	6.52	6.51	6.26	6.99
Total sales	7.23	7.66	7.63	7.67	7.90
Residential Average Annual Kilowatt-Hour Use Per Customer	13,426	14,229	15,130	13,762	13,992
Residential Average Annual Revenue Per Customer	$1,489	$1,622	$1,693	$1,614	$1,640
Plant Nameplate Capacity Ratings (year-end) (megawatts)	3,088	3,156	3,156	3,156	3,156
Maximum Peak-Hour Demand (megawatts):					
Winter	2,168	2,618	2,792	2,392	2,385
Summer	2,435	2,462	2,638	2,522	2,458
Annual Load Factor (percent)	61.9	59.1	57.9	60.7	61.5
Plant Availability Fossil-Steam (percent)*	91.5	87.7	93.8	94.1	91.6
Source of Energy Supply (percent):					
Coal	22.8	34.9	43.0	40.0	58.7
Oil and gas	63.9	51.5	41.9	43.6	28.6

Purchased power -					
From non-affiliates	2.0	1.4	1.3	3.3	4.4
From affiliates	11.3	12.2	13.8	13.1	8.3
Total	100.0	100.0	100.0	100.0	100.0

* Beginning in 2012, plant availability is calculated as a weighted equivalent availability.

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SOUTHERN POWER COMPANY
FINANCIAL SECTION

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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Southern Power Company and Subsidiary Companies 2012 Annual Report

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

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in Internal Control—Integrated Framework 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, 2012.

/s/ Oscar C. Harper, IV
Oscar C. Harper, IV
President and Chief Executive Officer
/s/ Michael W. Southern
Michael W. Southern
Senior Vice President and Chief Financial Officer
February 27, 2013

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM
To the Board of Directors of
Southern Power Company

We have audited the accompanying consolidated balance sheets of Southern Power Company and Subsidiary Companies (the Company) (a wholly owned subsidiary of The Southern Company) as of December 31, 2012 and 2011, and the related consolidated statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2012. 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 consolidated financial statements (pages II-465 to II-487) present fairly, in all material respects, the financial position of Southern Power Company and Subsidiary Companies as of December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 27, 2013

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Southern Power Company and Subsidiary Companies 2012 Annual Report
OVERVIEW
Business Activities
Southern Power Company and its subsidiaries (the Company) construct, acquire, own, and manage generation assets, including renewable energy projects, and sell electricity at market-based rates in the wholesale market. The Company continues to execute its strategy through a combination of acquiring and constructing new power plants and by entering into power purchase agreements (PPAs) primarily with investor owned utilities, independent power producers, municipalities, and electric cooperatives. In general, the Company has constructed or acquired new generating capacity only after entering into long-term capacity contracts for the new facilities.
In June 2012, the Company completed construction of Plant Nacogdoches, a biomass generating plant near Sacul, Texas with a nameplate capacity of approximately 116 megawatts (MWs). The Company has a PPA covering the entire output of the plant from 2012 through 2032.
In December 2012, the Company 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. The Company has long-term PPAs for 540 MWs of the generating capacity of the plant.
In 2012, the Company and Turner Renewable Energy, Inc. (TRE), through Southern Turner Renewable Energy LLC (STR), a jointly-owned subsidiary owned 90% by the 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. The solar facility began commercial operation on July 21, 2012 and 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. The solar facility began commercial operation on October 28, 2012 and has a PPA covering the entire output of the plant from 2012 through 2032. Spectrum is constructing a 30-MW solar photovoltaic facility in North Las Vegas, Nevada. The solar facility is expected to begin commercial operation in mid-2013 and has a PPA covering the entire output of the plant from 2013 through 2038. These acquisitions added a total of 47 MWs of solar capacity to the Company's generation portfolio and are in accordance with the Company's overall growth strategy. See FUTURE EARNINGS POTENTIAL – "Acquisitions" herein and Note 2 to the financial statements for additional information.
As of December 31, 2012, the Company had units totaling 8,764 MWs nameplate capacity in commercial operation. The average remaining duration of the Company's wholesale contracts exceeds 10 years, which reduces remarketing risk. The Company has entered into long-term power sales agreements for an average of 77% of its available capacity for the next five years and 70% of its available capacity for the next 10 years. The Company's future earnings will depend on the parameters of the wholesale market and the efficient operation of its wholesale generating assets. See FUTURE EARNINGS POTENTIAL herein for additional information.
Key Performance Indicators
To evaluate operating results and to ensure the Company's ability to meet its contractual commitments to customers, the Company focuses on several key performance indicators. These indicators include peak season equivalent forced outage rate (Peak Season EFOR), contract availability, and net income. Peak Season EFOR defines the hours during peak demand times when the Company's generating units are not available due to forced outages (the lower the better). Contract availability measures the percentage of scheduled hours delivered. Net income is the primary measure of the Company's financial performance. The Company's actual performance in 2012 met or surpassed targets in these key performance areas. See RESULTS OF OPERATIONS herein for additional information on the Company's net income for 2012.
Earnings
The Company's 2012 net income was $175.3 million, a $13.1 million increase compared to 2011. This increase was primarily due to higher energy revenues from sales to affiliates under the Intercompany Interchange Contract (IIC),

higher capacity revenues due to an increase in total MWs of capacity under long-term contracts, lower fuel and purchase power expenses, lower interest expense, and a loss on early redemption of long-term debt in 2011. This increase was partially offset by lower energy revenues from non-affiliates, higher depreciation and amortization, and higher income tax expense.

The Company's 2011 net income was $162.2 million, a $30.9 million increase compared to 2010. This increase was primarily due to higher energy and capacity revenues. This increase was partially offset by higher fuel expenses, higher operations and maintenance expenses, a loss on early redemption of long-term debt, and higher depreciation and amortization.

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Southern Power Company and Subsidiary Companies 2012 Annual Report

RESULTS OF OPERATIONS
A condensed statement of income follows:

	Amount	Increase (Decrease) from Prior Year	
	2012	2012	2011
	(in millions)		
Operating revenues	$1,186.0	$(49.9)	$105.6
Fuel	426.3	(28.5)	63.3
Purchased power	93.3	(37.9)	(38.8)
Other operations and maintenance	173.1	1.5	23.3
Loss (gain) on sale of property	—	—	(0.5)
Depreciation and amortization	142.6	18.4	4.8
Taxes other than income taxes	19.3	1.6	(0.1)
Total operating expenses	854.6	(44.9)	52.0
Operating income	331.4	(5.0)	53.6
Interest expense, net of amounts capitalized	62.5	(14.8)	1.2
Loss on extinguishment of debt	—	19.8	(19.8)
Other income (expense), net	(1.0)	0.2	(1.2)
Income taxes	92.6	16.7	0.5
Net income	$175.3	$13.1	$30.9

Operating Revenues

Operating revenues for 2012 were $1.19 billion, reflecting a $49.9 million decrease from 2011. Details of operating revenues are as follows:

	2012	2011	2010
		(in millions)	
Capacity revenues —			
Affiliates	$125.9	$146.5	$190.6
Non-affiliates	372.6	322.7	257.4
Total	498.5	469.2	448.0
Energy revenues —			
Affiliates	35.6	39.3	46.1
Non-affiliates	346.7	482.9	401.1
Total	382.3	522.2	447.2
Total PPA revenues	880.8	991.4	895.2
Revenues not covered by PPA	298.0	237.8	228.2
Other revenues	7.2	6.7	6.9
Total Operating Revenues	$1,186.0	$1,235.9	$1,130.3

The decrease in operating revenues was primarily due to a $139.9 million decrease in energy sales under PPAs, reflecting a 25.8% reduction in the average price of energy and a 1.3% decrease in kilowatt-hours (KWH) sales. This decrease was partially offset by a $60.3 million increase in energy sales not covered by PPAs, reflecting a 78.5% increase in KWH sales, partially offset by a 29.7% reduction in the average price of energy. Overall, energy sales decreased $79.6 million, reflecting a 22.1% reduction in the average price of energy, partially offset by a 14.9% increase in KWH sales. The decrease in operating revenues from energy sales was partially offset by a $29.3 million increase in capacity revenues due to an increase in the total MWs of capacity under contract.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Southern Power Company and Subsidiary Companies 2012 Annual Report

Operating revenues in 2011 were $1.24 billion, a $105.6 million (9.3%) increase from 2010. This increase was primarily due to a $75.0 million increase in energy sales under PPAs, reflecting an 11.2% increase in KWH sales and a 5.1% increase in the average price of energy. This increase was also due to a $14.0 million increase in energy sales not covered by PPAs, reflecting a 48.5% increase in KWH sales, partially offset by a 28.4% reduction in the average price of energy. Overall, energy sales increased $89.0 million, reflecting a 17.1% increase in KWH sales, partially offset by a 3.3% decrease in the average price of energy. The increase in operating revenue from energy sales was also due to a $16.8 million increase in capacity revenue due to an increase in the total MWs of capacity under contract.
Wholesale revenues from sales to affiliated companies will vary depending on demand and the availability and cost of generating resources at each company. Sales to affiliate companies that are not covered by PPAs are made in accordance with the IIC, as approved by the Federal Energy Regulatory Commission (FERC).
Capacity revenues are an integral component of the Company's PPAs with both affiliate and non-affiliate customers and generally represent the greatest contribution to net income. Energy under the PPAs is generally sold at variable cost or is indexed to published gas indices. Energy revenues also include fees for support services, fuel storage, and unit start charges.

Fuel and Purchased Power Expenses

Fuel costs constitute the single largest expense for the Company. Additionally, the Company purchases a portion of its electricity needs from the wholesale market.
Details of the Company's fuel and purchased power expenditures are as follows:

	2012	2011	2010
		(in millions)	
Fuel	$426.3	$454.8	$391.5
Purchased power-non-affiliates	80.4	78.4	72.7
Purchased power-affiliates	12.9	52.9	97.4
Total fuel and purchased power expenses	$519.6	$586.1	$561.6

In 2012, total fuel and purchased power expenses decreased by $66.5 million (11.3%) compared to 2011. Total fuel and purchased power expenses decreased $183.6 million, primarily due to a 26.6% decrease in the average cost of fuel and a 23.0% decrease in the average cost of purchased power. This decrease was partially offset by a $117.1 million increase associated with a 21.4% net increase in the volume of KWHs generated and purchased. In 2011, total fuel and purchased power expenses increased by $24.5 million (4.4%) compared to 2010. Total fuel and purchased power expenses increased $144.2 million, primarily due to a 28.0% increase in KWHs generated and purchased. This increase was partially offset by a decrease of $119.7 million due to a 30.0% decrease in the cost of purchased power and a 12.1% decrease in the average cost of natural gas generation.
In 2012, fuel expense decreased by $28.5 million (6.3%) compared to 2011. Fuel expense decreased primarily due to a $155.7 million decrease associated with the cost of fuel, partially offset by a $127.2 million increase associated with the volume of KWHs generated. In 2011, fuel expense increased by $63.3 million (16.2%) compared to 2010. Fuel expense increased $126.7 million primarily due to an increase in the volume of KWHs generated, partially offset by a $63.4 million decrease due to a 12.1% decline in the average cost of natural gas generation.
In 2012, purchased power expense decreased $37.9 million (28.9%) compared to 2011. Purchased power expense decreased primarily due to a $27.8 million decrease associated with the cost of purchased power and a $10.1 million decrease associated with the volume of KWHs purchased. In 2011, purchased power expense decreased $38.8 million (22.8%) compared to 2010. Purchased power expense decreased $56.3 million associated with the cost of purchased power, partially offset by a $17.5 million increase due to an increase in the volume of KWHs purchased.
The Company's PPAs generally provide that the purchasers are responsible for substantially all of the cost of fuel. Consequently, any increase or decrease in fuel costs is generally accompanied by an increase or decrease in related fuel revenues and does not have a significant impact on net income. The Company is responsible for the cost of fuel

for generating units that are not covered under PPAs. Power from these generating units is sold into the market or sold to affiliates under the IIC.
Purchased power expenses will vary depending on demand and the availability and cost of generating resources available throughout the Southern Company system and other contract resources. Load requirements are submitted to the power pool on an hourly basis and are fulfilled with the lowest cost alternative, whether that is generation owned by the Company, affiliate-owned generation, or external purchases.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Southern Power Company and Subsidiary Companies 2012 Annual Report

Other Operations and Maintenance Expenses
In 2012, other operations and maintenance expenses increased $1.5 million (0.9%) compared to 2011. This increase was primarily due to a $7.8 million increase in administrative and general expenses due to expenses associated with business development and affiliate service company costs allocated based on load and fuel burn and a $1.2 million increase in transmission cost, partially offset by a $7.4 million decrease in generating plant scheduled outages and maintenance in 2012.
In 2011, other operations and maintenance expenses increased $23.3 million (15.7%) compared to 2010. This increase was primarily due to an increase of $17.1 million related to generating plant scheduled outages and maintenance, an increase of $3.3 million related to labor costs across the fleet, and a $4.9 million increase in administrative and general expenses due to costs associated with strategic planning, legal fees, and additional expenses in 2011 related to information technology upgrades. These increases were partially offset by a $4.1 million decrease attributable to additional expense recognized in 2010 associated with the passage of healthcare legislation.
Depreciation and Amortization
In 2012, depreciation and amortization increased $18.4 million (14.8%) compared to 2011. This increase was primarily due to a $17.2 million increase in depreciation resulting from an increase in plant in service, including the additions of Plant Nacogdoches, Plant Apex, Plant Granville, and Plant Cleveland, and a $2.5 million increase due to higher depreciation rates from the depreciation study adopted in January 2012, partially offset by a $1.3 million decrease in depreciation related to asset retirements.
In 2011, depreciation and amortization increased $4.8 million (4.1%) compared to 2010. This increase was primarily related to an $8.0 million increase in depreciation rates associated with increased starts and run-hours at the Company's generating plants, which shortened the estimated depreciable life of some components, and a $3.3 million increase associated with the acquisition of Plant Cimarron. These increases were partially offset by a $7.5 million decrease due to higher expenses in 2010 related to equipment retirements.
See ACCOUNTING POLICIES – "Depreciation" herein for additional information regarding the Company's ongoing review of depreciation estimates. See also Note 1 to the financial statements under "Depreciation" for additional information.
Interest Expense, Net of Amounts Capitalized
In 2012, interest expense, net of amounts capitalized decreased $14.8 million (19.2%) compared to 2011. This decrease was primarily due to a $13.7 million expense reduction associated with the refinancing of $575 million in long-term debt in December 2011 and a $1.1 million increase in capitalized interest associated with the construction of Plant Cleveland and Plant Nacogdoches.
In 2011, interest expense, net of amounts capitalized increased $1.2 million (1.6%) compared to 2010. This increase was primarily due to $5.9 million in interest expense associated with the issuance of new long-term debt, $0.7 million associated with settlements and changes in tax positions from prior periods, $0.6 million associated with losses on interest rate swaps on senior notes, and $0.5 million associated with an affiliate loan related to STR in the first quarter 2011. These increases were partially offset by $5.9 million of additional capitalized interest associated with the construction of Plant Cleveland and Plant Nacogdoches and a $1.1 million decrease as the result of an early redemption of senior notes.
Loss on Extinguishment of Debt
In December 2011, the Company recorded a loss of $19.8 million in connection with the early redemption of senior notes primarily related to the payment of a make-whole premium.
Other Income (Expense), Net
In 2012, other income (expense), net increased $0.2 million compared to 2011. This increase was primarily due to increased earnings of STR, which resulted in a larger allocation of earnings to noncontrolling interest.
In 2011, other income (expense), net decreased $1.2 million compared to 2010. This decrease was primarily due to the reclassification from accumulated other comprehensive income (AOCI) of an interest rate hedge associated with the

early redemption of senior notes in 2011 and profit recognized in 2010 on the construction contract with the Orlando Utilities Commission whereby the Company provided engineering, procurement, and construction services to build a combined cycle unit.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Southern Power Company and Subsidiary Companies 2012 Annual Report

Income Taxes

In 2012, income taxes increased $16.7 million (22.1%) compared to 2011. This increase was primarily due to an $11.9 million increase associated with higher pre-tax earnings and a $9.3 million increase in Alabama state income taxes due to a decrease in the state income tax deduction for federal income taxes paid, partially offset by a $2.2 million decrease due to the conclusion of prior year Internal Revenue Service (IRS) audits and a $1.7 million decrease related to an increase in tax benefit from investment tax credits (ITCs) compared to 2011.

In 2011, income taxes increased $0.5 million (0.7%) compared to 2010. This increase was primarily due to a $12.4 million increase associated with higher pre-tax earnings, a $5.0 million increase due to reduced tax benefit from the impact of ITCs associated with the construction of Plant Nacogdoches and Plant Cimarron, and a $2.1 million increase due to the loss of the production activities deduction. These increases were partially offset by a $14.5 million decrease associated with the application of a lower composite tax rate and a $3.7 million decrease related to higher than expected future utilization of net operating losses in the State of New Mexico.

Effects of Inflation

The Company is party to long-term contracts reflecting market-based rates, including inflation expectations. Any adverse effect of inflation on the Company's results of operations has not been substantial in recent years.

FUTURE EARNINGS POTENTIAL

General

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's competitive wholesale business. These factors include: the Company's ability to achieve sales growth while containing costs; regulatory matters; creditworthiness of customers; total generating capacity available in the Company's target market areas; the successful remarketing of capacity as current contracts expire; and the Company's ability to execute its acquisition strategy and to construct generating facilities.

Other factors that could influence future earnings include weather, demand, generation patterns, and operational limitations.

Power Sales Agreements

The Company's sales are primarily through long-term PPAs. The Company is working to maintain and expand its share of the wholesale market. The Company expects that demand for capacity will begin to develop within some of its existing market areas beginning in the 2014-2016 timeframe.

The Company's PPAs consist of two types of agreements. The first type, referred to as a unit or block sale, is a customer purchase from a dedicated plant unit where all or a portion of the generation from that unit is reserved for that customer. The Company typically has the ability to serve the unit or block sale customer from an alternate resource. The second type, referred to as requirements service, provides that the Company serve the customer's capacity and energy requirements from a combination of the customer's own generating units and from Company resources not dedicated to serve unit or block sales. The Company has rights to purchase power provided by the requirements customers' resources when economically viable.

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Southern Power Company and Subsidiary Companies 2012 Annual Report

The Company has entered into the following PPAs over the past three years:

	Date	MWs	Plant	Contract Term
2012				
Nevada Power Company[(a)]	June 2012	20	Apex	7/12-12/37[(b)]
Jackson Electric Membership Corporation (EMC)	September 2012	65[(c)]	Franklin	1/16-12/35
GreyStone Power Corporation	September 2012	40[(c)]	Franklin	1/16-12/35
Nevada Power Company[(d)]	September 2012	30	Spectrum	6/13[(d)]-12/38[(b)]
Progress Energy Carolinas, Inc.[(e)]	October 2012	2.5	Granville	10/12-10/32
Cobb EMC	December 2012	100	Franklin	1/16-12/22
Cobb EMC	December 2012	225	Dahlberg	1/16-12/22
Cobb EMC	December 2012	108[(f)]	Unassigned	1/16-12/22
2011				
Georgia Power Company[(g)]	June 2011	75	Dahlberg	1/15-5/30
Georgia Power Company[(g)]	June 2011	625	Harris[(h)]	6/15-5/30
Georgia Power Company[(g)]	June 2011	298	Addison	1/15-5/30
Morgan Stanley Capital Group	August 2011	250	Franklin	1/16-12/25
Tampa Electric Company	December 2011	160	Oleander	1/13-12/15[(i)]
2010				
Tri State Generation and Transmission Association, Inc.[(j)]	March 2010	30	Cimarron	12/10-11/35
City of Seneca	June 2010	30[(f)]	Unassigned	7/10-6/15
Georgia EMCs[(k)]	October 2010[(k)]	423[(f)]	Unassigned	1/15-12/27[(k)]

(a) Contract assumed through the Apex acquisition on June 29, 2012.
(b) These agreements commence on the operation date and continue for a period of 25 years from January 1 immediately following the commercial operation date.
(c) These agreements, signed on September 7, 2012, have an option to reduce the amount by 5MWs.
(d) Contract assumed through the Spectrum acquisition on September 28, 2012. Commercial operation of the Spectrum solar facility is expected to begin in mid-2013.
(e) Contract assumed through the Granville acquisition on October 16, 2012.
(f) Represents estimated average annual capacity purchases.
(g) These agreements were approved by the Georgia Public Service Commission on March 20, 2012 and accepted by the FERC on November 21, 2012.
(h) This agreement is contracted with Plant Franklin from June 2015 through December 2015.
(i) This agreement, signed on December 16, 2011, has an option for extension which, if signed by July 1, 2013, would extend the term to December 2017.
(j) Contract assumed through the Cimarron acquisition in March 2010.
(k) These agreements, signed in October and December 2010, are extensions of current agreements with 11 Georgia EMCs. Nine agreements were extended from 2015 through 2024, one agreement was extended from 2018 through 2027, and one agreement was extended from 2018 through 2024.

The Company has PPAs with some of Southern Company's traditional operating companies, other investor owned utilities, independent power producers, municipalities, electric cooperatives, and an energy marketing firm. Although some of the Company's PPAs are with the traditional operating companies, the Company's generating facilities are not in the traditional operating companies' regulated rate bases, and the Company is not able to seek recovery from the traditional operating companies' ratepayers for construction, repair, environmental, or maintenance costs. The

Company expects that the capacity payments in the PPAs will produce sufficient cash flows to cover costs, pay debt service, and provide an equity return. However, the Company's overall profit will depend on numerous factors, including efficient operation of its generating facilities and demand under the Company's PPAs.

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Southern Power Company and Subsidiary Companies 2012 Annual Report

As a general matter, existing PPAs provide that the purchasers are responsible for either procuring the fuel or reimbursing the Company for the cost of fuel relating to the energy delivered under such PPAs. To the extent a particular generating facility does not meet the operational requirements contemplated in the PPAs, the Company may be responsible for excess fuel costs. With respect to fuel transportation risk, most of the Company's PPAs provide that the counterparties are responsible for transporting the fuel to the particular generating facility.

Fixed and variable operation and maintenance costs will be recovered through capacity charges based on dollars-per-kilowatt year or energy charges based on dollars-per-MW hour. In general, the Company has long-term service contracts with General Electric International, Inc., Siemens Electric, Inc., and First Solar, Inc. to reduce its exposure to certain operation and maintenance costs relating to such vendors' applicable equipment.

Many of the Company's PPAs have provisions that require the posting of collateral or an acceptable substitute guarantee in the event that Standard & Poor's Rating Services, a division of The McGraw Hill Companies, Inc. (S&P) or Moody's Investors Service, Inc. (Moody's) downgrades the credit ratings of the counterparty to an unacceptable credit rating or if the counterparty is not rated or fails to maintain a minimum coverage ratio. The PPAs are expected to provide the Company with a stable source of revenue during their respective terms.

The Company has entered into long-term power sales agreements for an average of 77% of its available capacity for the next five years and 70% of its available capacity for the next 10 years.

Environmental Matters

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 possible additional federal or state legislation or regulations related to global climate change, air quality, water quality, or other environmental and health concerns could also significantly affect the Company.

New environmental legislation or regulations, such as requirements related to greenhouse gases or changes to existing statutes or regulations, could affect many areas of the Company's operations. While the Company's PPAs generally contain provisions that permit charging the counterparty with some of the new costs incurred as a result of changes in environmental laws and regulations, the full impact of any such regulatory or legislative changes cannot be determined at this time.

Because the Company's units are newer gas-fired generating facilities, costs associated with environmental compliance for these facilities have been less significant than for similarly situated coal-fired generating facilities or older gas-fired generating facilities. Environmental, natural resource, and land use concerns, including the applicability of air quality limitations, the availability of water withdrawal rights, uncertainties regarding aesthetic impacts such as increased light or noise, and concerns about potential adverse health impacts can, however, increase the cost of siting and operating any type of future electric generating facility. The impact of such statutes and regulations on the Company cannot be determined at this time.

Climate Change Litigation

Kivalina Case

In 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs allege that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that some of the defendants (including Southern Company) acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. In 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case. On September 21, 2012, the U.S. Court of Appeals for the Ninth Circuit upheld the U.S. District Court for the Northern District of California's dismissal of the case. On November 27, 2012, the U.S. Court of Appeals for the Ninth Circuit denied the plaintiffs' request for review of the decision. On February 25, 2013, the plaintiffs filed a petition for writ of certiorari with the U.S. Supreme Court. Southern Company believes that these claims are without merit. The ultimate outcome of this matter cannot be determined at this time.

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Hurricane Katrina Case

In 2005, immediately following Hurricane Katrina, a lawsuit was filed in the U.S. District Court for the Southern District of Mississippi by Ned Comer on behalf of Mississippi residents seeking recovery for property damage and personal injuries caused by Hurricane Katrina. In 2006, the plaintiffs amended the complaint to include Southern Company and many other electric utilities, oil companies, chemical companies, and coal producers. The plaintiffs allege that the defendants contributed to climate change, which contributed to the intensity of Hurricane Katrina. In 2007, the U.S. District Court for the Southern District of Mississippi dismissed the case. On appeal to the U.S. Court of Appeals for the Fifth Circuit, a three-judge panel reversed the U.S. District Court for the Southern District of Mississippi, holding that the case could proceed, but, on rehearing, the full U.S. Court of Appeals for the Fifth Circuit dismissed the plaintiffs' appeal, resulting in reinstatement of the decision of the U.S. District Court for the Southern District of Mississippi in favor of the defendants. In May 2011, the plaintiffs filed an amended version of their class action complaint, arguing that the earlier dismissal was on procedural grounds and under Mississippi law the plaintiffs have a right to re-file. The amended complaint was also filed against numerous chemical, coal, oil, and utility companies, including the Company. On March 20, 2012, the U.S. District Court for the Southern District of Mississippi dismissed the plaintiffs' amended complaint. On April 16, 2012, the plaintiffs appealed the case to the U.S. Court of Appeals for the Fifth Circuit. The Company believes that these claims are without merit. The ultimate outcome of this matter cannot be determined at this time.

Environmental Statutes and Regulations

Air Quality

Revisions to the National Ambient Air Quality Standard for nitrogen dioxide (NO_2), which established a new one-hour standard, became effective in 2010. On February 29, 2012, the new NO_2 standard became effective. The EPA designated the entire country as "unclassifiable/attainment" under the new standard, with no nonattainment areas designated. However, the new NO_2 standard could result in significant additional compliance and operational costs for units that require new source permitting.

On January 31, 2013, the Environmental Protection Agency (EPA) published the final Industrial Boiler Maximum Achievable Control Technology (IB MACT) rule establishing emissions limits and/or work practice standards for various hazardous air pollutants emitted from industrial boilers, including biomass boilers and start-up boilers. Compliance for existing sources will be required by early 2016. Compliance for new sources will begin upon startup.

Each of the states in which the Company has fossil generation is subject to the requirements of the Clean Air Interstate Rule (CAIR), which calls for phased reductions in sulfur dioxide and nitrogen oxide 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 August 2011, the EPA adopted the Cross State Air Pollution Rule (CSAPR) to replace CAIR effective January 1, 2012. However, in December 2011, the U.S. Court of Appeals for the District of Columbia Circuit stayed the rule, and on August 21, 2012, vacated CSAPR in its entirety and directed the EPA to continue to administer CAIR pending the EPA's development of a valid replacement. On January 24, 2013, the U.S. Court of Appeals for the District of Columbia Circuit denied requests by the EPA and other parties for rehearing.

On August 29, 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 Alabama, Florida, Georgia, 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. If finalized as proposed, this new requirement could result in significant additional compliance and operational costs.

The Company has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the existing and new environmental requirements discussed above. The impacts of the NO_2 standards, IB MACT rule, CAIR and any future replacement 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 additional compliance costs that could affect results of operations, cash flows, and financial condition if such costs are not

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recovered through PPAs. Further, higher costs that are recovered through regulated rates at other utilities could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

Water Quality

In April 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 has entered into an amended settlement agreement to extend the deadline for issuing a final rule until June 27, 2013. If finalized as proposed, some of the Company's facilities may be subject to additional capital expenditures and compliance costs. Also, results of operations, cash flows, and financial condition could be impacted if such costs are not recovered through PPAs. Based on a preliminary assessment of the impact of the proposed rules, the Company estimates compliance costs to be immaterial. The ultimate outcome of this rulemaking will depend on the final rule and the outcome of any legal challenges and cannot be determined at this time.

The EPA has announced its determination that revision of the current effluent guidelines for steam electric power plants is warranted and has stated that it intends to propose such revisions by April 2013 and finalize the revisions by May 2014. New advanced wastewater treatment requirements are expected and may result in the installation of additional controls on certain of the Company's facilities, which could result in additional capital expenditures and compliance costs. The impact of the revised guidelines will depend on the specific technology requirements of the final rule and, therefore, cannot be determined at this time.

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. 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 April 13, 2012, the EPA published proposed regulations to establish standards of performance for greenhouse gas emissions from new fossil fuel steam electric generating units. The EPA has also announced plans to develop federal guidelines for states to establish greenhouse gas emissions performance standards for existing sources. The impact of this rulemaking will depend on the scope and specific requirements of the final rule and the outcome of any legal challenges and, therefore, cannot be determined at this time.

Although the outcome of federal, state, and international initiatives cannot be determined at this time, additional restrictions on the Company's greenhouse gas emissions at the federal or state level could result in additional compliance costs, including capital expenditures. Additional compliance costs could affect results of operations, cash flows, and financial condition if such costs are not recovered through PPAs. Further, higher costs that are recovered through regulated rates at other utilities 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 reported 2011 greenhouse gas emissions of approximately 10 million metric tons of carbon dioxide equivalent. The preliminary estimate of the Company's 2012 greenhouse gas emissions on the same basis is approximately 12 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, which is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units.

Income Tax Matters

Investment Tax Credits

In February 2009, President Obama signed into law the American Recovery and Reinvestment Act of 2009 (ARRA). Major tax incentives in the ARRA included renewable energy incentives. The Company received ITCs under the renewable energy incentives related to Plant Nacogdoches, Plant Cimarron, Plant Apex, and Plant Granville which have had a material impact on cash flows and net income. On January 2, 2013, the American Taxpayer Relief Act of 2012 (ATRA) was signed into law. The ATRA retroactively extended several renewable energy incentives through 2013, including extending investment tax credits for biomass projects which begin construction before January 1, 2014. See Note 1 to the financial statements under "Investment Tax Credits" and Note 5 to the financial statements under "Effective Tax Rate" for additional information.

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Bonus Depreciation
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 to be placed in service in 2013), which will have a positive impact on the future cash flows of the Company through 2013.
The ATRA retroactively extended several tax credits through 2013 and extended 50% bonus depreciation for property to be 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 will have a positive impact on the future cash flows of the Company through 2014.
Due to the significant amount of estimated bonus depreciation for 2013, tax credit utilization will be deferred. Consequently, the Company's positive cash flow benefit is estimated to be between $105 million and $115 million in 2013. See Note 5 to the financial statements under "Current and Deferred Income Taxes" for additional information.
Acquisitions
Granville Solar, LLC Acquisition
On October 16, 2012, the Company, through STR, acquired all of the outstanding membership interests of Granville from Sun Edison, LLC, the original developer of the project. Granville constructed and owns a 2.5-MW solar photovoltaic facility in Oxford, North Carolina. The solar facility began commercial operation on October 28, 2012. The output of the plant is contracted under a 20-year PPA with Progress Energy Carolinas, Inc. that began in October 2012. See Note 2 to the financial statements for additional information.
Spectrum Nevada Solar, LLC Acquisition
On September 28, 2012, the Company, through STR, acquired all of the outstanding membership interests of Spectrum from Sun Edison, LLC, the original developer of the project. Spectrum is constructing a 30-MW solar photovoltaic facility in North Las Vegas, Nevada. The solar facility is expected to begin commercial operation in mid-2013. The output of the plant is contracted under a 25-year PPA with Nevada Power Company, a subsidiary of NV Energy, Inc., that will begin in 2013. See Note 2 to the financial statements for additional information.
Apex Nevada Solar, LLC Acquisition
On June 29, 2012, the Company, through STR, acquired all of the outstanding membership interests of Apex from Sun Edison, LLC, the original developer of the project. Apex constructed and owns a 20-MW solar photovoltaic facility in North Las Vegas, Nevada. The solar facility began commercial operation on July 21, 2012. The output of the plant is contracted under a 25-year PPA with Nevada Power Company, a subsidiary of NV Energy, Inc., that began in July 2012. See Note 2 to the financial statements for additional information.
Other Matters
The Company is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of business. The Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as 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 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 and other matters being litigated which may affect future earnings potential.

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ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

The Company prepares its consolidated 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.

Revenue Recognition

The Company's revenue recognition depends on appropriate classification and documentation of transactions in accordance with GAAP. In general, the Company's power sale transactions can be classified in one of four categories: leases, non-derivatives or normal sale derivatives, derivatives designated as cash flow hedges, and derivatives not designated as hedges. For more information on derivative transactions, see FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" herein and Notes 1 and 9 to the financial statements. The Company's revenues are dependent upon significant judgments used to determine the appropriate transaction classification, which must be documented upon the inception of each contract.

Lease Transactions

The Company considers the following factors to determine whether the sales contract is a lease:

- Assessing whether specific property is explicitly or implicitly identified in the agreement;
- Determining whether the fulfillment of the arrangement is dependent on the use of the identified property; and
- Assessing whether the arrangement conveys to the purchaser the right to use the identified property.

If the contract meets the above criteria for a lease, the Company performs further analysis as to whether the lease is classified as operating or capital. All of the Company's power sales contracts classified as leases are accounted for as operating leases and revenue is recognized on a straight-line basis over the term of the contract.

Non-Derivative and Normal Sale Derivative Transactions

If the sales contract is not considered a lease, the Company further considers the following factors to determine proper transaction classification:

- Assessing whether a sales contract meets the definition of a derivative;
- Assessing whether a sales contract meets the definition of a capacity contract;
- Assessing the probability at inception and throughout the term of the individual contract that the contract will result in physical delivery; and
- Ensuring that the contract quantities do not exceed available generating capacity (including purchased capacity).

Contracts that do not meet the definition of a derivative or are designated as normal sales (i.e. capacity contracts which provide for the sale of electricity that involve physical delivery in quantities within the Company's available generating capacity) are exempt from fair value accounting in accordance with GAAP. As a result, such transactions are accounted for as executory contracts. The related capacity revenue is recognized on an accrual basis in amounts equal to the lesser of the cumulative levelized amount or the cumulative amount billable under the contract over the respective contract periods. Revenues are recorded on a gross or net basis in accordance with GAAP. Contracts recorded on the accrual basis represented the majority of the Company's operating revenues for the years ended December 31, 2012, 2011, and 2010.

Cash Flow Hedge Transactions

The Company further considers the following in designating other derivative contracts for the sale of electricity as cash flow hedges of anticipated sale transactions:

- Identifying the hedging instrument, the hedged transaction, and the nature of the risk being hedged; and
- Assessing hedge effectiveness at inception and throughout the contract term.

These contracts are marked to market through AOCI over the life of the contract. Realized gains and losses are then recognized in revenues as incurred.

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Mark-to-Market Transactions

Contracts for sales and purchases of electricity, which meet the definition of a derivative and that either do not qualify or are not designated as normal sales or as cash flow hedges, are marked-to-market and recorded directly through net income.

Impairment of Long Lived Assets and Intangibles

The Company's investments in long-lived assets are primarily generation assets, whether in service or under construction. The Company's intangible assets consist of acquired PPAs that are amortized over the term of the PPAs and goodwill resulting from acquisitions. The Company evaluates the carrying value of these assets in accordance with accounting standards whenever indicators of potential impairment exist, or annually in the case of goodwill. Examples of impairment indicators could include significant changes in construction schedules, current period losses combined with a history of losses or a projection of continuing losses, a significant decrease in market prices, and the inability to remarket generating capacity for an extended period. If an indicator exists, the asset is tested for recoverability by comparing the asset carrying value to the sum of the undiscounted expected future cash flows directly attributable to the asset. A high degree of judgment is required in developing estimates related to these evaluations, which are based on projections of various factors, including the following:

- Future demand for electricity based on projections of economic growth and estimates of available generating capacity;
- Future power and natural gas prices, which have been quite volatile in recent years; and
- Future operating costs.

Acquisition Accounting

The Company acquires generation assets as part of its overall growth strategy. The Company accounts for business acquisitions from non-affiliates as business combinations utilizing the acquisition method in accordance with GAAP. Accordingly, the Company 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 the Company for successful or potential acquisitions have been expensed as incurred.

Contingent Obligations

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

Depreciation

Depreciation of the original cost of assets is computed under the straight-line method and applies a composite depreciation rate based on the assets' estimated useful lives determined by management. The primary assets in property, plant, and equipment are power plants, which have estimated composite lives ranging from 21 to 35 years. These lives reflect a weighted average of the significant components (retirement units) that make up the plants. Key judgments impacting the estimated lives of component parts include estimates of run-hours and starts which can impact the future utility of these components. The Company reviews its estimated useful lives and salvage values on an ongoing basis. The results of these reviews could result in changes which could have a material impact on net income in the near term.

When property subject to composite depreciation is retired or otherwise disposed of in the normal course of business, its cost is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation is removed from the accounts and a gain or loss is recognized.

Investment Tax Credits

Under the ARRA, certain construction costs related to Plant Nacogdoches, Plant Cimarron, Plant Apex, Plant Spectrum, and Plant Granville are eligible for ITCs. A high degree of judgment is required in determining which construction expenditures qualify for ITCs. See Note 1 to the financial statements under "Investment Tax Credits" for additional information.

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FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2012. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements as needed to meet its future capital and liquidity needs. See "Sources of Capital" herein for additional information on lines of credit.

Net cash provided from operating activities totaled $573.1 million in 2012, an increase of $160.8 million as compared to 2011. This increase was primarily due to an increase in deferred income tax, partially offset by a decrease in cash received for ITCs and an adjustment for the loss on extinguishment of debt in 2011. Net cash provided from operating activities totaled $412.4 million in 2011, an increase of $85.5 million compared to 2010. This increase was primarily due to an increase in ITCs received in 2011.

Net cash used for investing activities totaled $332.5 million, $328.4 million, and $408.1 million in 2012, 2011, and 2010, respectively. Net cash used for investing activities in 2012 was primarily due to the Apex, Spectrum, and Granville acquisitions, construction spending on Plant Nacogdoches and Plant Cleveland, and payments pursuant to long-term service agreements. Net cash used for investing activities in 2011 was primarily due to construction spending on Plant Nacogdoches and Plant Cleveland. Net cash used for investing activities in 2010 was primarily due to construction spending on Plant Nacogdoches and Plant Cleveland and the acquisition of Plant Cimarron.

Net cash used for financing activities totaled $229.0 million and $81.3 million in 2012 and 2011, respectively. Net cash provided from financing activities totaled $88.3 million in 2010. Net cash used for financing activities in 2012 was primarily due to payment of common stock dividends and a decrease in notes payable. Net cash used for financing activities in 2011 was primarily due to a decrease in notes payable. Net cash provided from financing activities in 2010 was primarily due to an increase in notes payable. Fluctuations in cash flow from financing activities vary year to year based on capital needs and the maturity or redemption of securities.

Significant asset changes in the balance sheet during 2012 include an increase in property, plant, and equipment, primarily due to the Apex, Spectrum, and Granville acquisitions and an increase in prepaid service agreements-current, primarily due to the timing of plant outages.

Significant liability and stockholder's equity changes in the balance sheet during 2012 include an increase in accumulated deferred income taxes due to bonus depreciation and an increase in deferred investment tax credits due to additional spending on Plant Nacogdoches and the Apex and Granville acquisitions. This increase was partially offset by a decrease in notes payable to non-affiliates due to the timing of operating cash flows.

Sources of Capital

The Company may use operating cash flows, external funds, or equity capital or loans from Southern Company to finance any new projects, acquisitions, and ongoing capital requirements. The Company expects to generate external funds from the issuance of unsecured senior debt and commercial paper or utilization of credit arrangements from banks. However, the amount, type, and timing of any future financings, if needed, will depend upon prevailing market conditions, regulatory approval, and other factors.

The issuance of securities by the Company is subject to regulatory approval by the FERC. Additionally, with respect to the public offering of securities, the Company files registration statements with the Securities and Exchange Commission (SEC) under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the FERC, as well as the amounts registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

The Company's current liabilities frequently exceed current assets due to the use of short-term debt as a funding source, as well as cash needs, which can fluctuate significantly due to the seasonality of the business.

To meet liquidity and capital resource requirements, the Company had at December 31, 2012 cash and cash equivalents of approximately $28.6 million and a committed credit facility of $500 million (Facility) expiring in 2016. As of December 31, 2012, the total amount available under the Facility was $500 million. The Facility does not

contain a material adverse change clause applicable to borrowing.
The Facility contains a covenant that limits the ratio of debt to capitalization (each as defined in the Facility) to a maximum of 65% and contains a cross default provision that is restricted only to indebtedness of the Company. The Company is currently in compliance with all covenants in the Facility.

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Proceeds from the Facility may be used for working capital and general corporate purposes as well as liquidity support for the Company's commercial paper program. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

The Company's commercial paper program is used to finance acquisition and construction costs related to electric generating facilities and for general corporate purposes.

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 (in millions)	Weighted Average Interest Rate	Average Outstanding (in millions)	Weighted Average Interest Rate	Maximum Amount Outstanding (in millions)
December 31, 2012:					
Commercial paper	$71	0.5 %	$170	0.5 %	$309
December 31, 2011:					
Commercial paper	$180	0.5 %	$175	0.4 %	$305
December 31, 2010:					
Commercial paper	$204	0.4 %	$169	0.4 %	$259

(a) Average and maximum amounts are based upon daily balances during the twelve-month periods ended December 31, 2012, 2011, and 2010.

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

Financing Activities

During 2012, the Company prepaid $2.5 million on a long-term debt related to STR.

During 2012, the Company issued a $4.1 million promissory note, due June 15, 2032, to TRE related to the financing of Apex.

During 2012, the Company issued a $0.9 million promissory note, due September 30, 2032, to TRE related to the financing of Spectrum.

During 2012, the Company issued a $0.5 million promissory note, due October 31, 2032, to TRE related to the financing of Granville.

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

The maximum potential collateral requirements under these contracts at December 31, 2012 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements (in millions)
At BBB and Baa2	$9

At BBB- and/or Baa3	487
Below BBB- and/or Baa3	1,226

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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.

In addition, through the acquisition of Plant Rowan, the Company assumed a PPA with North Carolina Municipal Power Agency No. 1 that could require collateral, but not accelerated payment, in the event of a downgrade of the Company's credit. The PPA requires credit assurances without stating a specific credit rating. The amount of collateral required would depend upon actual losses, if any, resulting from a credit downgrade.

Market Price Risk

The Company is exposed to market risks, including changes in interest rates, certain energy-related commodity prices, and, occasionally, currency exchange rates. To manage the volatility attributable to these exposures, the Company takes 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.

At December 31, 2012, the Company had $4.1 million of long-term variable debt outstanding. The effect on annualized interest expense related to long-term debt if the Company sustained a 100 basis point change in interest rates is immaterial. Since a significant portion of outstanding indebtedness bears interest at fixed rates, the Company is not aware of any facts or circumstances that would significantly affect exposure on existing indebtedness in the near term. However, the impact on future financing costs cannot be determined at this time.

Because energy from the Company's facilities is primarily sold under long-term PPAs with tolling agreements and provisions shifting substantially all of the responsibility for fuel cost to the counterparties, the Company's exposure to market volatility in commodity fuel prices and prices of electricity is generally limited. However, the Company has been and may continue to be exposed to market volatility in energy-related commodity prices as a result of sales of uncontracted generating capacity.

The changes in fair value of energy-related derivative contracts for the years ended December 31 were as follows:

	2012 Changes	2011 Changes
	Fair Value (in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	$(9.2)	$(3.5)
Contracts realized or settled	15.6	5.6
Current period changes[(a)]	(5.6)	(11.3)
Contracts outstanding at the end of the period, assets (liabilities), net	$0.8	$(9.2)

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

For the year ended December 31, 2012, there was a $10.0 million increase in the fair value positions of the energy-related derivative contracts associated with both power and natural gas positions. For the year ended December 31, 2011, there was a $5.7 million decrease in the fair value positions of the energy related derivative contracts associated with both power and natural gas positions.

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The changes were attributable to both the volume and the prices of power and natural gas as follows:

	December 31, 2012	December 31, 2011
Power – net purchased or (sold)		
Megawatt hours (MWH) (in millions)	—	0.1
Weighted average contract cost per MWH above (below) market prices (in dollars)	$—	$(1.04)
Natural gas net purchased		
Commodity – million British thermal unit (mmBtu)	5.0	8.3
Commodity – weighted average contract cost per mmBtu above (below) market prices (in dollars)	$(0.02)	$1.18

At December 31, the net fair value of energy-related derivative contracts by hedge designation was reflected in the financial statements as follows:

Asset (Liability) Derivatives	2012	2011
	(in millions)	
Cash flow hedges	$—	$(0.8)
Not designated	0.8	(8.4)
Total fair value	$0.8	$(9.2)

Gains and losses on energy-related derivatives used by the Company to hedge anticipated purchases and sales are initially deferred in AOCI 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.

For the Company's energy-related derivatives not designated as hedging instruments, a substantial 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 the years ended December 31, 2012, 2011, and 2010.

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 8 to the financial statements for further discussion of fair value measurements. The maturities of the energy-related derivative contracts and the level of the fair value hierarchy in which they fall at December 31, 2012 were as follows:

	Fair Value Measurements December 31, 2012			
	Total	Maturity		
	Fair Value	Year 1	Years 2&3	Years 4&5
	(in millions)			
Level 1	$—	$—	$—	$—
Level 2	0.8	(0.3)	—	1.1
Level 3	—	—	—	—
Fair value of contracts outstanding at end of period	$0.8	$(0.3)	$—	$1.1

The Company is exposed to market price risk in the event of nonperformance by counterparties to energy-related derivative contracts. The Company only enters into agreements with counterparties that have investment grade credit ratings by S&P and Moody's or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. See Note 1 to the financial statements under "Financial Instruments" and Note 9 to the financial statements for additional

information.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Southern Power Company and Subsidiary Companies 2012 Annual Report

Capital Requirements and Contractual Obligations

The capital program of the Company is currently estimated to be $909.6 million for 2013, $751.8 million for 2014, and $735.7 million for 2015. These amounts include estimates for potential plant acquisitions and new construction as well as ongoing capital improvements and work to be performed under long-term service agreements. Planned expenditures for plant acquisitions may vary due to market opportunities and the Company's ability to execute its growth strategy. Actual construction costs may vary from these estimates because of changes in factors such as: business conditions; environmental statutes and regulations; FERC rules and regulations; load projections; legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; and the cost of capital.

In addition, pursuant to an agreement with TRE, on or after November 25, 2015, TRE may require the Company to purchase its noncontrolling interest in STR at fair market value.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, leases, derivative obligations, and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 1, 5, 6, 7, and 9 to the financial statements for additional information.

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Southern Power Company and Subsidiary Companies 2012 Annual Report

Contractual Obligations

	2013	2014-2015	2016-2017	After 2017	Uncertain Timing [c]	Total
	(in millions)					
Long-term debt[a] —						
Principal	$—	$525.0	$—	$779.1	$—	$1,304.1
Interest	68.1	124.5	85.0	944.6	—	1,222.2
Financial derivative obligations[b]	0.7	0.6	—	—	—	1.3
Operating leases[c]	1.3	3.0	2.6	40.3	—	47.2
Unrecognized tax benefits[d]	—	—	—	—	2.9	2.9
Purchase commitments —						
Capital[e]	799.7	1,374.4	—	—	—	2,174.1
Fuel[f]	469.4	688.4	345.5	277.4	—	1,780.7
Purchased power[g]	50.4	105.1	77.4	164.3	—	397.2
Other[h]	51.7	184.9	142.0	534.1	—	912.7
Transmission agreements[i]	0.9	1.8	3.6	3.6	—	9.9
Total	$1,442.2	$3,007.7	$656.1	$2,743.4	$2.9	$7,852.3

(a) All amounts are reflected based on final maturity dates. The Company plans to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

(b) For additional information, see Notes 1 and 9 to the financial statements.

(c) Operating lease commitments are subject to price escalation based on the Consumer Price Index for All Urban Consumers for the Plant Stanton Unit A land lease.

(d) The timing related to the realization of $2.9 million in unrecognized tax benefits in individual years beyond 12 months cannot be reasonably and reliably estimated due to uncertainties in the timing of the effective settlement of tax positions. See Note 5 to the financial statements under "Unrecognized Tax Benefits" for additional information.

(e) The Company provides estimated capital expenditures for a three-year period. Amounts represent current estimates of total expenditures, excluding capital expenditures covered under long-term service agreements.

(f) Primarily commitments to purchase, transport, and store natural gas fuel. Amounts reflected are based on contracted cost and may contain provisions for price escalation. Amounts reflected for natural gas purchase commitments are based on various indices at the time of delivery and have been estimated based on the New York Mercantile Exchange future prices at December 31, 2012.

(g) Purchased power commitments of $36.1 million in 2013, $74.4 million in 2014-2015, $77.4 million in 2016-2017, and $164.3 million after 2017 will be resold under a third party agreement to EnergyUnited EMC. The purchases will be resold at cost.

(h) Includes long-term service agreements and operation and maintenance agreements. Long-term service agreements include price escalation based on inflation indices.

(i) Transmission commitments are based on Southern Company's current tariff rate for point-to-point transmission.

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Southern Power Company and Subsidiary Companies 2012 Annual Report

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2012 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning the strategic goals for the Company's business, customer growth, economic recovery, fuel and environmental cost recovery, current and proposed environmental regulations and related estimated expenditures, access to sources of capital, financing activities, impact of the Tax Relief Act, impact of the ATRA, estimated sales and purchases under new power sale and purchase agreements, timing of expected future capacity need in existing markets, completion of construction projects, filings with federal regulatory authorities, plans and estimated costs for new generation resources, 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 and emissions of sulfur, nitrogen, carbon, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, financial reform legislation, 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 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, 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 and 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;
- advances in technology;
- state and federal rate regulations;
- 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, 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.

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CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2012, 2011, and 2010
Southern Power Company and Subsidiary Companies 2012 Annual Report

	2012	2011	2010
	(in thousands)		
Operating Revenues:			
Wholesale revenues, non-affiliates	$753,653	$870,607	$752,772
Wholesale revenues, affiliates	425,180	358,585	370,630
Other revenues	7,215	6,769	6,939
Total operating revenues	1,186,048	1,235,961	1,130,341
Operating Expenses:			
Fuel	426,257	454,790	391,535
Purchased power, non-affiliates	80,438	78,368	72,657
Purchased power, affiliates	12,915	52,924	97,408
Other operations and maintenance	173,074	171,538	148,238
Loss (gain) on sale of property	—	—	478
Depreciation and amortization	142,624	124,204	119,333
Taxes other than income taxes	19,309	17,686	17,831
Total operating expenses	854,617	899,510	847,480
Operating Income	331,431	336,451	282,861
Other Income and (Expense):			
Interest expense, net of amounts capitalized	(62,503)	(77,334)	(76,120)
Loss on extinguishment of debt	—	(19,806)	—
Other income (expense), net	(1,022)	(1,223)	(76)
Total other income and (expense)	(63,525)	(98,363)	(76,196)
Earnings Before Income Taxes	267,906	238,088	206,665
Income taxes	92,621	75,857	75,356
Net Income	$175,285	$162,231	$131,309

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

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CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2012, 2011, and 2010
Southern Power Company and Subsidiary Companies 2012 Annual Report

	2012	2011	2010
	(in thousands)		
Net Income	$175,285	$162,231	$131,309
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $(90), $55, and $591, respectively	(136)	65	938
Reclassification adjustment for amounts included in net income, net of tax of $3,919, $4,837, and $3,894, respectively	6,189	7,125	6,444
Total other comprehensive income (loss)	6,053	7,190	7,382
Comprehensive Income	$181,338	$169,421	$138,691

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

CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2012, 2011, and 2010
Southern Power Company and Subsidiary Companies 2012 Annual Report

	2012	2011	2010
	(in thousands)		
Operating Activities:			
Net income	$175,285	$162,231	$131,309
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization, total	153,635	138,787	133,109
Deferred income taxes	228,780	4,481	64,530
Investment tax credits	45,047	84,723	26,400
Deferred revenues	(12,633)	(10,594)	(5,586)
Mark-to-market adjustments	(9,275)	8,000	1,492
Loss on extinguishment of debt	—	19,806	—
Other, net	3,104	495	6,078
Changes in certain current assets and liabilities —			
-Receivables	(1,384)	10,448	(23,198)
-Fossil fuel stock	(8,578)	532	2,604
-Materials and supplies	(7,825)	(4,097)	443
-Prepaid income taxes	(3,223)	10,693	4,784
-Other current assets	(1,624)	(485)	(985)
-Accounts payable	10,514	(6,138)	1,469
-Accrued taxes	431	2,134	(16,024)
-Accrued interest	385	(8,102)	53
-Other current liabilities	492	(535)	362
Net cash provided from operating activities	573,131	412,379	326,840
Investing Activities:			
Property additions	(116,633)	(254,725)	(299,602)
Cash paid for acquisitions	(124,059)	—	(105,042)
Sale of property	—	25	4,000
Change in construction payables, net	(27,387)	(14,291)	34,851
Payments pursuant to long-term service agreements	(63,932)	(57,969)	(41,598)
Other investing activities	(446)	(1,412)	(721)
Net cash used for investing activities	(332,457)	(328,372)	(408,112)
Financing Activities:			
Increase (decrease) in notes payable, net	(108,552)	(90,267)	150,840
Proceeds —			
Capital contributions	(662)	127,241	36,507
Senior notes	—	575,000	—
Other long-term debt	5,470	—	4,759
Redemptions —			
Senior notes	—	(575,000)	—
Other long-term debt	(2,450)	(3,691)	—
Premium for early debt extinguishment	—	(19,375)	—
Payment of common stock dividends	(127,000)	(91,200)	(107,100)
Other financing activities	4,169	(3,976)	3,318

Net cash provided from (used for) financing activities	(229,025)	(81,268)	88,324
Net Change in Cash and Cash Equivalents	11,649	2,739	7,052
Cash and Cash Equivalents at Beginning of Year	16,943	14,204	7,152
Cash and Cash Equivalents at End of Year	$28,592	$16,943	$14,204
Supplemental Cash Flow Information:			
Cash paid during the period for —			
Interest (net of $19,092, $18,001 and $12,110 capitalized, respectively)	$50,248	$74,989	$63,229
Income taxes (net of refunds and investment tax credits)	(175,269)	(26,486)	(6,246)
Noncash transactions — accrued property additions at year-end	11,203	32,590	46,764

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

CONSOLIDATED BALANCE SHEETS
At December 31, 2012 and 2011
Southern Power Company and Subsidiary Companies 2012 Annual Report

Assets	2012	2011
	(in thousands)	
Current Assets:		
Cash and cash equivalents	$28,592	$16,943
Receivables —		
Customer accounts receivable	62,857	59,360
Other accounts receivable	3,135	2,122
Affiliated companies	38,269	36,508
Fossil fuel stock, at average cost	21,616	13,038
Materials and supplies, at average cost	46,370	37,603
Prepaid service agreements — current	80,629	28,621
Prepaid income taxes	4,498	5,192
Other prepaid expenses	5,637	4,645
Assets from risk management activities	375	177
Total current assets	291,978	204,209
Property, Plant, and Equipment:		
In service	4,059,839	3,167,840
Less accumulated provision for depreciation	786,620	652,087
Plant in service, net of depreciation	3,273,219	2,515,753
Construction work in progress	24,835	666,280
Total property, plant, and equipment	3,298,054	3,182,033
Other Property and Investments:		
Goodwill	1,839	1,839
Other intangible assets, net of amortization of $3,141 and $1,476 at December 31, 2012 and December 31, 2011, respectively	45,979	47,644
Total other property and investments	47,818	49,483
Deferred Charges and Other Assets:		
Prepaid long-term service agreements	100,921	115,838
Other deferred charges and assets — affiliated	3,468	3,029
Other deferred charges and assets — non-affiliated	37,688	26,385
Total deferred charges and other assets	142,077	145,252
Total Assets	$3,779,927	$3,580,977

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

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CONSOLIDATED BALANCE SHEETS
At December 31, 2012 and 2011
Southern Power Company and Subsidiary Companies 2012 Annual Report

Liabilities and Stockholder's Equity	2012	2011
	(in thousands)	
Current Liabilities:		
Securities due within one year	$259	$555
Notes payable — non-affiliated	70,968	179,520
Accounts payable —		
Affiliated	65,832	63,609
Other	26,204	44,321
Accrued taxes —		
Accrued income taxes	87	2,548
Other accrued taxes	3,031	2,158
Accrued interest	22,259	21,874
Liabilities from risk management activities	669	9,651
Other current liabilities	8,263	7,401
Total current liabilities	197,572	331,637
Long-Term Debt:		
Senior notes —		
4.875% due 2015	525,000	525,000
6.375% due 2036	200,000	200,000
5.15% due 2041	575,000	575,000
Other long-term notes (3.25% due 2032)	3,828	513
Unamortized debt premium	2,557	2,645
Unamortized debt discount	(286)	(400)
Long-term debt	1,306,099	1,302,758
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	550,685	319,790
Investment tax credits	167,130	125,065
Deferred capacity revenues — affiliated	19,514	20,637
Other deferred credits and liabilities — affiliated	2,638	3,618
Other deferred credits and liabilities — non-affiliated	5,863	4,965
Total deferred credits and other liabilities	745,830	474,075
Total Liabilities	2,249,501	2,108,470
Redeemable Noncontrolling Interest	8,069	3,825
Common Stockholder's Equity:		
Common stock, par value $0.01 per share —		
Authorized - 1,000,000 shares		
Outstanding - 1,000 shares	—	—
Paid-in capital	1,027,548	1,028,210
Retained earnings	495,585	447,301
Accumulated other comprehensive income (loss)	(776)	(6,829)
Total common stockholder's equity	1,522,357	1,468,682
Total Liabilities and Stockholder's Equity	$3,779,927	$3,580,977

Commitments and Contingent Matters (See notes)
The accompanying notes are an integral part of these financial statements.

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CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
For the Years Ended December 31, 2012, 2011, and 2010
Southern Power Company and Subsidiary Companies 2012 Annual Report

	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
	(in thousands)					
Balance at December 31, 2009	1	$—	$864,462	$352,061	$(21,401)	$1,195,122
Net income	—	—	—	131,309	—	131,309
Capital contributions from parent company	—	—	36,507	—	—	36,507
Other comprehensive income (loss)	—	—	—	—	7,382	7,382
Cash dividends on common stock	—	—	—	(107,100)	—	(107,100)
Balance at December 31, 2010	1	—	900,969	376,270	(14,019)	1,263,220
Net income	—	—	—	162,231	—	162,231
Capital contributions from parent company	—	—	127,241	—	—	127,241
Other comprehensive income (loss)	—	—	—	—	7,190	7,190
Cash dividends on common stock	—	—	—	(91,200)	—	(91,200)
Balance at December 31, 2011	1	—	1,028,210	447,301	(6,829)	1,468,682
Net income	—	—	—	175,285	—	175,285
Capital contributions from parent company	—	—	(662)	—	—	(662)
Other comprehensive income (loss)	—	—	—	—	6,053	6,053
Cash dividends on common stock	—	—	—	(127,000)	—	(127,000)
Other	—	—	—	(1)	—	(1)
Balance at December 31, 2012	1	$—	$1,027,548	$495,585	$(776)	$1,522,357

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

NOTES TO FINANCIAL STATEMENTS
Southern Power Company and Subsidiary Companies 2012 Annual Report
1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES
General
Southern Power Company is a wholly-owned subsidiary of The Southern Company (Southern Company), which is also the parent company of four traditional operating companies, 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, Georgia Power Company (GPC), Gulf Power Company, and Mississippi Power Company – are vertically integrated utilities providing electric service in four Southeastern states. Southern Power Company and its subsidiaries (the Company) construct, acquire, own, and manage generation assets, including renewable energy projects, and sell 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 Company is subject to regulation by the Federal Energy Regulatory Commission (FERC). The Company follows generally accepted accounting principles (GAAP). 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.
The financial statements include the accounts of the Company and its wholly-owned subsidiaries, Southern Company - Florida LLC, Oleander Power Project, LP, and Nacogdoches Power LLC, which own, operate, and maintain the Company's ownership interests in Plant Stanton Unit A, Plant Oleander, and Plant Nacogdoches, respectively. The financial statements also include the accounts of the Company's wholly-owned subsidiary, Southern Renewable Energy, Inc, (SRE). SRE was formed to construct, acquire, own, and manage renewable generation assets and sell electricity at market-based prices in the wholesale market. Through Southern Turner Renewable Energy LLC (STR), a jointly-owned subsidiary owned 90% by SRE and 10% by Turner Renewable Energy, Inc. (TRE), SRE and its subsidiaries own, operate, and maintain Plant Cimarron, Plant Apex, and Plant Granville and are constructing Plant Spectrum. All intercompany accounts and transactions have been eliminated in consolidation.
Affiliate Transactions
The Company has an agreement with SCS under which the following services are rendered to the Company at amounts in compliance with FERC regulation: general and design engineering, purchasing, accounting, finance and treasury, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, labor, and other services with respect to business and operations and transactions associated with the Southern Company system's fleet of generating units. Because the Company has no employees, all employee-related charges are rendered at amounts in compliance with FERC regulation under agreements with SCS. Costs for these services from SCS amounted to approximately $125.4 million in 2012, $112.7 million in 2011, and $105.2 million in 2010. Approximately $107.7 million in 2012, $87.9 million in 2011, and $89.6 million in 2010 were operations and maintenance expenses; the remainder was recorded to construction work in progress (CWIP), other assets, and billings in excess of cost on a construction contract. 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 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 several agreements with SCS for transmission services. Transmission purchased from affiliates totaled $6.6 million in 2012, $7.1 million in 2011, and $7.8 million in 2010. All charges were billed to the Company based on the Southern Company Open Access Transmission Tariff as filed with the FERC.

Total billings for all power purchase agreements (PPAs) with affiliates totaled $159.9 million, $175.9 million, and $230.8 million in 2012, 2011, and 2010, respectively. Included in these billings were $19.0 million, $20.6 million, and $30.5 million of "Deferred capacity revenues – affiliated" recorded on the balance sheets at December 31, 2012, 2011, and 2010, respectively. Revenue recognized under affiliate PPAs accounted for as operating leases totaled $76.2 million, $75.6 million, and $68.1 million in 2012, 2011, and 2010, respectively. The Company and the traditional operating companies may jointly enter into various types of wholesale energy, natural gas, and certain other contracts, either directly or through SCS as agent. Each participating company may be jointly and severally liable for the obligations incurred under these agreements.

NOTES (continued)
Southern Power Company and Subsidiary Companies 2012 Annual Report

The Company and the traditional operating companies generally settle amounts related to the above transactions on a monthly basis in the month following the performance of such services or the purchase or sale of electricity.

Acquisition Accounting

The Company acquires generation assets as part of its overall growth strategy. The Company accounts for business acquisitions from non-affiliates as business combinations utilizing the acquisition method in accordance with GAAP. Accordingly, the Company 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 the Company for successful or potential acquisitions have been expensed as incurred.

Revenues

The Company sells capacity at rates specified under contractual terms for long-term PPAs. These PPAs are generally accounted for as operating leases, non-derivatives, or normal sale derivatives. Capacity revenues from PPAs classified as operating leases are recognized on a straight-line basis over the term of the agreement. Capacity revenues from PPAs classified as non-derivatives or normal sales are recognized at the lesser of the levelized amount or the amount billable under the contract over the respective contract periods. When multiple contracts exist with the same counterparty, the revenues from each contract are accounted for as separate arrangements.

The Company may also enter into contracts to sell short-term capacity in the wholesale electricity markets. These sales are generally classified as mark-to-market derivatives and net unrealized gains (losses) on such contracts are recorded in wholesale revenues. See Note 9 to the financial statements for further information.

Energy revenues and other contingent revenues are recognized in the period the energy is delivered or the service is rendered. All revenues under solar PPAs are accounted for as contingent revenues and recognized as services are performed. Transmission revenues and other fees are recognized as earned as other operating revenues. Revenues are recorded on a gross basis for all full requirements PPAs. See "Financial Instruments" herein for additional information.

Significant portions of the Company's revenues have been derived from certain customers pursuant to PPAs. For the year ended December 31, 2012, Florida Power & Light Company (FPL) accounted for 12.8% of total revenues, GPC accounted for 12.5% of total revenues, and Progress Energy Florida, Inc. accounted for 5.9% of total revenues. For the year ended December 31, 2011, FPL accounted for 14.7% of total revenues, GPC accounted for 14.0% of total revenues, and Progress Energy Carolinas, Inc. (Progress Energy Carolinas) accounted for 8.3% of total revenues. For the year ended December 31, 2010, GPC accounted for 17.7% of total revenues, FPL accounted for 11.4% of total revenues, and Progress Energy Carolinas accounted for 8.2% of total revenues.

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel costs also include emissions allowances which are expensed as the emissions occur.

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. 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.

Investment Tax Credits

Under the American Recovery and Reinvestment Act of 2009 (ARRA), certain construction costs related to Plant Nacogdoches, Plant Cimarron, Plant Apex, Plant Spectrum, and Plant Granville are eligible for investment tax credits

(ITCs). The credits are recorded as a deferred credit, which will be amortized to income tax expense over the life of the asset, and the tax basis of the asset is reduced by 50% of the credits received, resulting in a deferred tax asset. The Company 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 for construction projects two years or longer, or otherwise, when placed in service. The deferred tax asset will reverse and be recorded to income tax expense over the useful life of the asset once placed in service. The credits received during the year are shown within operating activities in the consolidated statements of cash flows.

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Property, Plant, and Equipment
The Company's depreciable property, plant, and equipment consists entirely of generation assets.
Property, plant, and equipment is stated at original cost. Original cost includes: materials, direct labor incurred by contractors and affiliated companies, minor items of property, and interest capitalized. Interest is capitalized on qualifying projects during the development and construction period. The cost to replace significant items of property defined as retirement units is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to other operations and maintenance expense as incurred.
Depreciation
Depreciation of the original cost of assets is computed under the straight-line method and applies a composite depreciation rate based on the assets' estimated useful lives determined by the Company. The primary assets in property, plant, and equipment are power plants, which have estimated composite depreciable lives ranging from 21 to 35. These lives reflect a composite of the significant components (retirement units) that make up the plants. The Company reviews its estimated useful lives and salvage values on an ongoing basis. The results of these reviews could result in changes which could have a material impact on net income in the near term.
When property subject to composite depreciation is retired or otherwise disposed of in the normal course of business, its cost is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation is removed from the balance sheet accounts and a gain or loss is recognized.
Impairment of Long-Lived Assets and Intangibles
The Company evaluates long-lived assets and finite-lived intangibles for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The Company's intangible assets consist of acquired PPAs that are amortized over the term of the PPA and goodwill resulting from acquisitions. The average term of these PPAs is 20 years. The determination of whether an impairment has occurred is based on an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If the estimate of undiscounted future cash flows is less than the carrying value of the asset, the fair value of the asset is determined and a loss is recorded. 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.
The amortization expense for the PPAs is as follows:

	Amortization Expense (in millions)
2012	$1.7
2013	2.5
2014	2.5
2015	2.5
2016	2.4
2017 and beyond	36.0
Total	$47.6

Deferred Project Development Costs
The Company capitalizes project development costs once it is determined that it is probable that a specific site will be acquired and a plant constructed. These costs include professional services, permits, and other costs directly related to the construction of a project. In addition, the Company has acquired emission reduction credits necessary for future unspecified construction in areas designated by the Environmental Protection Agency (EPA) as non-attainment areas

for nitrogen oxide or volatile organic compound emissions. These credits are reflected on the balance sheets at historical cost. Deferred project development costs, including the cost of emission reduction offsets to be surrendered, are generally transferred to CWIP upon commencement of construction. The total deferred project development costs were $11.2 million at December 31, 2012, $9.9 million at December 31, 2011, and $9.6 million at December 31, 2010.

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Cash and Cash Equivalents
For purposes of the financial statements, temporary cash investments are considered cash equivalents. Temporary cash investments are securities with original maturities of 90 days or less.
Materials and Supplies
Generally, materials and supplies include the average cost of 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 cost of oil, natural gas, biomass, and emissions allowances. The Company maintains oil inventory for use at Plant Dahlberg, Plant Oleander, Plant Rowan, Plant Addison (formerly known as West Georgia), and Plant Cleveland. The Company has contracts in place for natural gas storage. These contracts help to ensure normal operations of the Company's natural gas generating units. The Company maintains biomass inventory for use at Plant Nacogdoches. Inventory is maintained using the weighted average cost method. Fuel inventory and emissions allowances are recorded at actual cost when purchased and then expensed at weighted average cost as used. Emissions allowances granted by the EPA are included at zero cost.
Financial Instruments
The Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, 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 8 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. This results in the deferral of related gains and losses in accumulated other comprehensive income (AOCI) 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 in the financial statement line item where they will eventually settle. See Note 9 for additional information. Cash flows from derivatives are classified on the statement of cash flows in the same category as the hedged item.
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, 2012.
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.
Other Income and (Expense)
Other income and (expense) includes non-operating revenues and expenses. Revenues are recognized when earned and expenses are recognized when incurred.
In December 2011, the Company redeemed its $575 million aggregate principal amount of Series B 6.25% Senior Notes due July 15, 2012. The loss recognized for the early redemption was $19.8 million primarily related to the payment of a make whole premium.
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 of amounts included in net income.

Variable Interest Entities

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

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The Company has certain wholly-owned subsidiaries that are determined to be VIEs. The Company is considered the primary beneficiary of these VIEs because it controls the most significant activities of the VIEs, including operating and maintaining the respective assets, and has the obligation to absorb expected losses of these VIEs to the extent of its equity interests.

2. ACQUISITIONS AND DIVESTITURES

Granville Solar, LLC Acquisition

On October 16, 2012, the Company, through STR, acquired all of the outstanding membership interests of Granville Solar, LLC (Granville) from Sun Edison, LLC, the original developer of the project. Granville constructed and owns a 2.5 megawatt (MW) solar photovoltaic facility in Oxford, North Carolina. The solar facility began commercial operation on October 28, 2012. The output of the plant is contracted under a 20-year PPA with Progress Energy Carolinas that began in October 2012. This PPA is being accounted for as an operating lease. The acquisition is in accordance with the Company's overall growth strategy.

The Company's acquisition of Granville included cash consideration of $10.4 million. As of December 31, 2012, the allocation of the purchase price to individual assets has not been finalized. As of the acquisition date, the entire purchase price was recorded as CWIP and moved to plant in service on the balance sheets herein, once it was placed in service. Revenues and earnings with respect to Granville for the period ended December 31, 2012 were immaterial.

Spectrum Nevada Solar, LLC Acquisition

On September 28, 2012, the Company, through STR, acquired all of the outstanding membership interests of Spectrum Nevada Solar, LLC (Spectrum) from Sun Edison, LLC, the original developer of the project. Spectrum is constructing a 30-MW solar photovoltaic facility in North Las Vegas, Nevada. The solar facility is expected to begin commercial operation in mid-2013. The output of the plant is contracted under a 25-year PPA with Nevada Power Company, a subsidiary of NV Energy, Inc., that will begin in 2013. This PPA will be accounted for as an operating lease. The acquisition is in accordance with the Company's overall growth strategy.

The Company's acquisition of Spectrum consisted of cash consideration of $17.6 million paid at closing. An estimated $99.9 million will be paid to complete the construction of the solar facility. As of December 31, 2012, the allocation of the purchase price to individual assets has not been finalized. As of December 31, 2012, the $17.6 million purchase price was reflected in CWIP on the balance sheets herein.

Apex Nevada Solar, LLC Acquisition

On June 29, 2012, the Company, through STR, acquired all of the outstanding membership interests of Apex Nevada Solar, LLC (Apex) from Sun Edison, LLC, the original developer of the project. Apex constructed and owns a 20-MW solar photovoltaic facility in North Las Vegas, Nevada. The solar facility began commercial operation on July 21, 2012. The output of the plant is contracted under a 25-year PPA with Nevada Power Company, a subsidiary of NV Energy, Inc., that began in July 2012. This PPA is being accounted for as an operating lease. The acquisition is in accordance with the Company's overall growth strategy.

The Company's acquisition of Apex included consideration of $102.0 million. As of December 31, 2012, the allocation of the purchase price to individual assets has not been finalized. As of the acquisition date, the entire purchase price was recorded as CWIP and moved to plant in service on the balance sheets herein, once it was placed in service. Revenues and earnings with respect to Apex for the period ended December 31, 2012 were immaterial.

Southern Renewable Energy, Inc. Acquisition

In March 2011, Southern Company transferred ownership in its wholly-owned subsidiary, SRE, to the Company. The Company's acquisition of SRE was a transfer of net assets among entities under common control; therefore, the assets and liabilities of SRE were transferred from Southern Company to the Company at historical cost. The consolidated financial statements of the Company have been revised to include the financial condition and the results of operations of SRE since its inception in 2010. The effect of this revision was an increase of $1.3 million in net income for the year ended December 31, 2010. There was no impact on AOCI related to this change.

In 2010, the Company, through STR, entered into an engineering, construction, and procurement agreement with First Solar, Inc. for Plant Cimarron, a 30-MW solar photovoltaic plant near Cimarron, New Mexico, and assumed the associated PPA. In 2010, Plant Cimarron began commercial operation. The output from the plant is contracted under a PPA with Tri-State Generation and Transmission Association, Inc. (Tri-State). The Tri-State agreement began in December 2010 and expires in 2035. This PPA is accounted for as an operating lease.

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The Company's acquisition of Cimarron included cash consideration of approximately $100 million and was allocated to property, plant, and equipment. The acquisition is in accordance with the Company's overall growth strategy. There are no contingent consideration arrangements and no significant liabilities arising from contingencies as a result of this acquisition. No goodwill or other intangible assets were recorded as a result of this acquisition.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

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

Climate Change Litigation

Kivalina Case

In 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs allege that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that some of the defendants (including Southern Company) acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. In 2009, the U.S. District Court for the Northern District of California granted the defendants' motions to dismiss the case. On September 21, 2012, the U.S. Court of Appeals for the Ninth Circuit upheld the U.S. District Court for the Northern District of California's dismissal of the case. On November 27, 2012, the U.S. Court of Appeals for the Ninth Circuit denied the plaintiffs' request for review of the decision. On February 25, 2013, the plaintiffs filed a petition for writ of certiorari with the U.S. Supreme Court. Southern Company believes that these claims are without merit. While Southern Company believes the likelihood of loss is remote based on existing case law, it is not possible to predict with certainty whether the Company will incur any liability in connection with this matter. The ultimate outcome of this matter cannot be determined at this time.

Hurricane Katrina Case

In 2005, immediately following Hurricane Katrina, a lawsuit was filed in the U.S. District Court for the Southern District of Mississippi by Ned Comer on behalf of Mississippi residents seeking recovery for property damage and personal injuries caused by Hurricane Katrina. In 2006, the plaintiffs amended the complaint to include Southern Company and many other electric utilities, oil companies, chemical companies, and coal producers. The plaintiffs allege that the defendants contributed to climate change, which contributed to the intensity of Hurricane Katrina. In 2007, the U.S. District Court for the Southern District of Mississippi dismissed the case. On appeal to the U.S. Court of Appeals for the Fifth Circuit, a three-judge panel reversed the U.S. District Court for the Southern District of Mississippi, holding that the case could proceed, but, on rehearing, the full U.S. Court of Appeals for the Fifth Circuit dismissed the plaintiffs' appeal, resulting in reinstatement of the decision of the U.S. District Court for the Southern District of Mississippi in favor of the defendants. In May 2011, the plaintiffs filed an amended version of their class action complaint, arguing that the earlier dismissal was on procedural grounds and under Mississippi law the plaintiffs have a right to re-file. The amended complaint was also filed against numerous chemical, coal, oil, and utility companies, including the Company. On March 20, 2012, the U.S. District Court for the Southern District of Mississippi dismissed the plaintiffs' amended complaint. On April 16, 2012, the plaintiffs appealed the case to the U.S. Court of Appeals for the Fifth Circuit. The Company believes that these claims are without merit. While the Company believes the likelihood of loss is remote based on existing case law, it is not possible to predict with certainty whether the Company will incur any liability in connection with this matter. The ultimate outcome of this matter cannot be determined at this time.

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4. JOINT OWNERSHIP AGREEMENTS

The Company is a 65% owner of Plant Stanton A, a combined-cycle project with a nameplate capacity of 659 MWs. The unit is co-owned by the Orlando Utilities Commission (28%), Florida Municipal Power Agency (3.5%), and Kissimmee Utility Authority (3.5%). The Company has a service agreement with SCS whereby SCS is responsible for the operation and maintenance of Plant Stanton A. As of December 31, 2012, $155.8 million was recorded in plant in service with associated accumulated depreciation of $36.3 million. These amounts represent the Company's share of the total plant assets and each owner is responsible for providing its own financing. The Company's proportionate share of Plant Stanton A's operating expense is included in the corresponding operating expenses in the statements of income.

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, Mississippi, and Texas. In addition, the Company files separate company income tax returns for the States of Florida, New Mexico, North Carolina, and South Carolina. Under a joint consolidated income tax allocation agreement, each 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 Internal Revenue Service (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:

	2012	2011	2010
	(in millions)		
Federal —			
Current	$(133.1)	$61.6	$4.3
Deferred	210.4	12.4	46.5
	77.3	74.0	50.8
State —			
Current	(3.0)	9.8	6.5
Deferred	18.3	(7.9)	18.1
	15.3	1.9	24.6
Total	$92.6	$75.9	$75.4

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

	2012	2011
	(in millions)	
Deferred tax liabilities —		
Accelerated depreciation and other property basis differences	$632.9	$394.8
Basis difference on asset transfers	3.1	3.3
Other	6.2	4.6
Total	642.2	402.7
Deferred tax assets —		
Federal effect of state deferred taxes	25.2	18.6
Net basis difference on investment tax credits	28.6	21.8
Basis difference on asset transfers	3.9	4.9
Alternative minimum tax carryforward	1.1	1.1
Unrealized loss on interest rate swaps	15.7	19.1
Levelized capacity revenues	4.5	8.2
Other	12.7	11.1
Total	91.7	84.8
Total deferred tax liabilities, net	550.5	317.9
Portion included in current income taxes	0.2	1.9
Accumulated deferred income taxes	$550.7	$319.8

Deferred tax liabilities are the result of property related timing differences primarily due to bonus depreciation. The transfer of the Plant McIntosh construction project to GPC in 2004 resulted in a deferred gain for federal income tax purposes. GPC is reimbursing the Company for the related tax liability balance of $3.1 million. Of this total, $0.3 million is included in the balance sheets in "Receivables – Affiliated companies" and the remainder is included in "Other deferred charges and assets – affiliated."

Deferred tax assets consist primarily of timing differences related to net basis differences on ITCs, the recognition of capacity revenues, and the unrealized loss on interest rate swaps reflected in AOCI. The transfer of Plants Dahlberg, Wansley, and Franklin to the Company from GPC in 2001 also resulted in a deferred gain for federal income tax purposes. The Company will reimburse GPC for the related tax asset of $3.9 million. Of this total, $1.3 million is included in the balance sheets in "Accounts payable – Affiliated" and the remainder is included in "Other deferred credits and liabilities – affiliated."

At December 31, 2012 and December 31, 2011, the Company had a State of New Mexico net operating loss (NOL) carryforward of $117.7 million and $88.7 million, respectively. The NOL carryforward resulted in a deferred tax asset as of December 31, 2012 and December 31, 2011 of $5.4 million and $4.0 million, respectively. However, the Company has established a valuation allowance due to the remote likelihood that the full tax benefit will be realized. During 2012, the estimated amount of NOL utilization decreased resulting in a $1.0 million increase in the valuation allowance. The valuation allowance was $4.0 million as of December 31, 2012 and $3.0 million as of December 31, 2011. Of the NOL balance at December 31, 2012, $4.2 million and $1.2 million will expire in 2015 and 2017, respectively.

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 to be placed in service in 2013). The application of the bonus depreciation provisions in the

Tax Relief Act significantly increased deferred tax liabilities related to accelerated depreciation.

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

	2012	2011	2010
Federal statutory rate	35.0 %	35.0 %	35.0 %
State income tax, net of federal deduction	3.7	0.6	7.7
Amortization of ITC	(1.0)	(0.4)	—
ITC basis difference	(2.6)	(3.1)	(5.6)
Other	(0.6)	(0.3)	(0.7)
Effective income tax rate	34.5 %	31.8 %	36.4 %

The Company's effective tax rate increased in 2012 primarily as a result of a decrease in the Alabama income tax deduction for federal income taxes paid.
In February 2009, President Obama signed into law the ARRA. Major tax incentives in the ARRA included renewable energy incentives. The Company received ITCs under the renewable energy incentives related to Plant Nacogdoches, Plant Cimarron, Plant Apex, and Plant Granville which had a material impact on cash flows and net income.
ITCs received in 2012 for the construction of Plant Nacogdoches, Plant Cimarron, Plant Apex, and Plant Granville were $45.0 million. The tax benefit of the basis difference reduced income tax expense by $6.9 million in 2012. See Note 1 under "Investment Tax Credits" for additional information.
ITCs received in 2011 for the construction of Plant Nacogdoches and Plant Cimarron were $84.7 million, which includes $42.9 million earned in 2010. The tax benefit of the basis difference reduced income tax expense by $7.3 million in 2011.
ITCs received in 2010 for the construction of Plant Nacogdoches were $26.4 million; the tax benefit of the basis difference reduced income tax expense by $6.9 million. The tax benefit of the basis difference related to ITCs associated with the construction of Plant Cimarron reduced tax expense by $4.6 million in 2010.
Unrecognized Tax Benefits
For 2012, the total amount of unrecognized tax benefits increased $0.3 million, resulting in a balance of $2.9 million as of December 31, 2012.
Changes during the year in unrecognized tax benefits were as follows:

	2012	2011	2010
	(in millions)		
Unrecognized tax benefits at beginning of year	$2.6	$2.3	$0.1
Tax positions from current periods	0.7	0.4	0.7
Tax positions from prior periods	(0.2)	(0.1)	1.5
Reductions due to settlements	(0.2)	—	—
Balance at end of year	$2.9	$2.6	$2.3

The increase in unrecognized tax benefits from current periods for 2012 relates primarily to the tax accounting method change for repairs-generation assets. See "Tax Method of Accounting for Repairs" herein for additional information.
The American Jobs Creation Act of 2004 created a tax deduction for a portion of income attributable to U.S. production activities as defined in Section 199 of the Internal Revenue Code (production activities deduction). The decrease in unrecognized tax benefits from prior periods relates to the settlement of the production activities deduction.

NOTES (continued)
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The impact on the Company's effective tax rate, if recognized, was as follows:

	2012	2011	2010
	(in millions)		
Tax positions impacting the effective tax rate	$0.3	$0.5	$0.6
Tax positions not impacting the effective tax rate	2.6	2.1	1.7
Balance of unrecognized tax benefits	$2.9	$2.6	$2.3

The tax positions impacting the effective tax rate for 2012 primarily relate to the investment tax credits realized in 2012. 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:

	2012	2011	2010
	(in millions)		
Interest accrued at beginning of year	$0.1	$—	$—
Interest accrued during the year	(0.1)	0.1	—
Balance at end of year	$—	$0.1	$—

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 associated with a majority of the Company's unrecognized tax positions will significantly increase or decrease within 12 months. The resolution of the tax accounting method change for repairs-generation assets, as well as the conclusion or settlement of 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 audited and closed all of Southern Company's consolidated federal income tax returns prior to 2009 and has settled its audits of Southern Company's consolidated federal income tax returns for 2009 and 2010, in principle, pending final approval. Additionally, the IRS has audited and closed Southern Company's 2011 consolidated federal income tax return. For tax years 2010 through 2013, Southern Company is a participant in the Compliance Assurance Process of the IRS. The audits for the Company's state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2007.

Tax Method of Accounting for Repairs

Southern Company submitted a tax accounting method change related to the deductibility of repair costs associated with its subsidiaries' generation, transmission, and distribution systems effective for the 2009 consolidated federal income tax return in 2010. In August 2011, the IRS issued a revenue procedure, which provides a safe harbor method of accounting that taxpayers may use to determine eligible repair costs for transmission and distribution property. The IRS continues to work with the utility industry in an effort to define eligible repair costs for generation assets in a consistent manner for all utilities. 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. The utility industry anticipates more detailed guidance concerning these regulations. Due to the uncertainty regarding the ultimate resolution of the repair costs for generation assets, an unrecognized tax position has been recorded for the tax accounting method change for repairs-generation assets. The ultimate outcome of this matter cannot be determined at this time; however, it is not expected to materially impact net income.

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6. FINANCING
Other Long-Term Notes
During 2012, the Company prepaid $2.5 million on a long-term debt related to STR.
During 2012, the Company issued a $4.1 million promissory note, due June 15, 2032, to TRE related to the financing of Apex.
During 2012, the Company issued a $0.9 million promissory note, due September 30, 2032, to TRE related to the financing of Spectrum.
During 2012, the Company issued a $0.5 million promissory note, due October 31, 2032, to TRE related to the financing of Granville.
Senior Notes
During 2012, the Company did not issue any senior notes.
During 2011, the Company issued $575 million aggregate principal amount of Series 2011A 5.15% Senior Notes due September 15, 2041. The proceeds of the issuance were used to redeem $575 million aggregate principal amount of Series B 6.25% Senior Notes due July 15, 2012.
At December 31, 2012 and 2011, the Company had $1.3 billion of senior notes outstanding.
Bank Credit Arrangements
In 2011, the Company terminated its existing credit arrangement and entered into a $500 million committed credit facility (Facility) expiring in 2016. There were no borrowings outstanding under the Facility at December 31, 2012 and December 31, 2011. The Facility does not contain a material adverse change clause at the time of borrowing.
The Company is required to pay a commitment fee on the unused balance of the Facility. This fee is less than 1/4 of 1%. The Facility contains a covenant that limits the ratio of debt to capitalization (each as defined in the Facility) to a maximum of 65%. The Facility also contains a cross default provision that is restricted only to indebtedness of the Company. The Company is currently in compliance with all covenants in the Facility.
Proceeds from the Facility may be used for working capital and general corporate purposes as well as liquidity support for the Company's commercial paper program.
The Company's commercial paper program is used to finance acquisition and construction costs related to electric generating facilities and for general corporate purposes. Commercial paper is included in notes payable in the balance sheets.
Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period		
	Amount Outstanding (in millions)	Weighted Average Interest Rate	
December 31, 2012:			
Commercial paper	$71	0.5	%
December 31, 2011:			
Commercial paper	$180	0.5	%

Dividend Restrictions
The Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital.
The indenture related to certain series of the Company's senior notes also contains certain limitations on the payment of common stock dividends. No dividends may be paid unless, as of the end of any calendar quarter, the Company's projected cash flows from fixed priced capacity PPAs are at least 80% of total projected cash flows for the next

12 months or the Company's debt to capitalization ratio is no greater than 60%. At December 31, 2012, the Company was in compliance with these ratios and had no other restrictions on its ability to pay dividends.

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7. COMMITMENTS

Fuel Agreements

SCS, as agent for the Company and the traditional operating companies, has entered into various fuel transportation and procurement agreements to supply a portion of the fuel (primarily natural gas) requirements for the operating facilities which are not recognized on the balance sheets. In 2012, 2011, and 2010, the Company incurred fuel expense of $426.3 million, $454.8 million, and $391.5 million, respectively, the majority of which was purchased under long-term commitments. The Company expects that a substantial amount of its future fuel needs will continue to be purchased under long-term commitments.

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and Southern Company's traditional operating companies. Under these agreements, each of the traditional operating companies and the Company may be jointly and severally liable. The credit rating of the Company is below that of the traditional operating companies; accordingly, Southern Company has entered into keep-well agreements with each of the traditional operating companies to ensure they will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of the Company as a contracting party under these agreements.

Operating Leases

The Company has operating lease agreements with various terms and expiration dates. Total rent expense was $0.8 million, $0.6 million, and $0.5 million for 2012, 2011, and 2010, respectively. These amounts include contingent rent expense related to the Plant Stanton Unit A land lease based on escalation in the Consumer Price Index for All Urban Consumers. The Company includes 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, 2012, estimated minimum lease payments under operating leases were $1.3 million in 2013, $1.6 million in 2014, $1.4 million in 2015, $1.3 million in 2016, $1.3 million in 2017, and $40.3 million in 2018 and thereafter. The majority of the committed future expenditures are land leases at solar facilities.

Redeemable Noncontrolling Interest

Pursuant to an agreement with TRE, on or after November 25, 2015, TRE may require the Company to purchase its noncontrolling interest in STR at fair market value.

8. FAIR VALUE MEASUREMENTS

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

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.
- Level 3 consists of unobservable market data. The input may reflect the assumptions of the Company of what a market participant would use in pricing an asset or liability. If there is little available market data, then the Company's own assumptions are the best available information. The need to use unobservable inputs would typically apply to long-term energy-related derivative contracts and generally results from the nature of the energy industry, as each participant forecasts its own power supply and demand and those of other participants, which directly impact the valuation of each unique contract.

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)
Southern Power Company and Subsidiary Companies 2012 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			
	Quoted Prices in Active Markets for Identical Assets	Significant Other Observable Inputs	Significant Unobservable Inputs	
As of December 31, 2012:	(Level 1)	(Level 2)	(Level 3)	Total
	(in millions)			
Assets:				
Energy-related derivatives	$—	$2.1	$—	$2.1
Cash equivalents	26.0	—	—	26.0
Total	$26.0	$2.1	$—	$28.1
Liabilities:				
Energy-related derivatives	$—	$1.3	$—	$1.3

As of December 31, 2011, 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			
	Quoted Prices in Active Markets for Identical Assets	Significant Other Observable Inputs	Significant Unobservable Inputs	
As of December 31, 2011:	(Level 1)	(Level 2)	(Level 3)	Total
	(in millions)			
Assets:				
Energy-related derivatives	$—	$0.6	$—	$0.6
Cash equivalents	14.2	—	—	14.2
Total	$14.2	$0.6	$—	$14.8
Liabilities:				
Energy-related derivatives	$—	$9.8	$—	$9.8

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 London Interbank Offered Rate interest rates. See Note 9 for additional information on how these derivatives are used.

NOTES (continued)
Southern Power Company and Subsidiary Companies 2012 Annual Report

As of December 31, 2012 and 2011, 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, 2012:	(in millions)			
Cash equivalents:				
Money market funds	$26.0	None	Daily	Not applicable
As of December 31, 2011:				
Cash equivalents:				
Money market funds	$14.2	None	Daily	Not applicable

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, 2012 and 2011, 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:		
2012	$1,306	$1,444
2011	$1,303	$1,397

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.

9. 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.

Energy-Related Derivatives

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. The Company 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, the Company has been and may continue to be exposed to market volatility in energy-related commodity prices as a result of sales of uncontracted generating capacity.

To mitigate residual risks relative to movements in electricity prices, the Company enters into physical fixed-price or heat rate 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.

NOTES (continued)
Southern Power Company and Subsidiary Companies 2012 Annual Report

Energy-related derivative contracts are accounted for in one of two methods:

- Cash Flow Hedges – Gains and losses on energy-related derivatives designated as cash flow hedges which are used to hedge anticipated purchases and sales and are initially deferred in AOCI 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, 2012, the net volume of energy-related derivative contracts for natural gas positions totaled 5.0 million mmBtu (million British thermal units), all of which expire by 2017, which is the longest non-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 maximum expected volume of natural gas subject to such a feature is immaterial.

Interest Rate Derivatives

The Company may also enter into interest rate derivatives from time to time 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 AOCI 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, 2012, there were no interest rate derivatives outstanding.

The estimated pre-tax loss that will be reclassified from AOCI to interest expense for the 12-month period ending December 31, 2013 is $6.5 million. The Company has deferred gains and losses that are expected to be amortized into earnings through 2016.

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NOTES (continued)
Southern Power Company and Subsidiary Companies 2012 Annual Report

Derivative Financial Statement Presentation and Amounts
At December 31, 2012 and 2011, the fair value of energy-related derivatives was reflected in the balance sheets as follows:

Derivative Category	Asset Derivatives Balance Sheet Location	2012	2011	Liability Derivatives Balance Sheet Location	2012	2011
		(in millions)			(in millions)	
Derivatives designated as hedging instruments in cash flow hedges						
Energy-related derivatives:	Assets from risk management activities	$—	$—	Liabilities from risk management activities	$—	$0.8
	Other deferred charges and assets – non-affiliated	—	—	Other deferred credits and liabilities – non-affiliated	—	—
Total derivatives designated as hedging instruments in cash flow hedges		$—	$—		$—	$0.8
Derivatives not designated as hedging instruments						
Energy-related derivatives:	Assets from risk management activities	$0.4	$0.2	Liabilities from risk management activities	$0.7	$8.8
	Other deferred charges and assets – non-affiliated	1.7	0.4	Other deferred credits and liabilities – non-affiliated	0.6	0.2
Total derivatives not designated as hedging instruments		$2.1	$0.6		$1.3	$9.0
Total		$2.1	$0.6		$1.3	$9.8

All derivative instruments are measured at fair value. See Note 8 for additional information.
For the years ended December 31, 2012, 2011, and 2010, the pre-tax effects of energy-related derivatives and interest rate derivatives designated as cash flow hedging instruments on the statements of income were as follows:

Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Recognized in AOCI on Derivative (Effective Portion)			Gain (Loss) Reclassified from AOCI into Income (Effective Portion)			
					Amount		
Derivative Category	2012	2011	2010	Statements of Income Location	2012	2011	2010
	(in millions)				(in millions)		
Energy-related derivatives	$(0.2)	$0.1	$1.5	Depreciation and amortization	$0.4	$0.4	$0.4
Interest rate derivatives	—	—	—	Interest expense, net of amounts capitalized	(10.5)	(11.4)	(10.8)

				Other income (expense), net	—	(1.0)	—
Total	$(0.2)	$0.1	$1.5		$(10.1)	$(12.0)	$(10.4)

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

NOTES (continued)
Southern Power Company and Subsidiary Companies 2012 Annual Report

For the Company's energy-related derivatives not designated as hedging instruments, a substantial 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 the years ended December 31, 2012, 2011, and 2010.

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, 2012, the fair value of derivative liabilities with contingent features was immaterial.

At December 31, 2012, 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 $15.1 million. 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 power pool participants has a credit rating change to below investment grade.

NOTES (continued)
Southern Power Company and Subsidiary Companies 2012 Annual Report

10. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)
Summarized quarterly financial information for 2012 and 2011 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income
	(in thousands)		
March 2012	$253,681	$56,343	$29,316
June 2012	285,805	90,038	46,602
September 2012	354,971	119,234	68,376
December 2012	291,591	65,816	30,991
March 2011	$281,787	$77,347	$37,743
June 2011	305,209	86,792	44,601
September 2011	362,565	108,708	56,071
December 2011	286,400	63,604	23,816

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

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SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA 2008-2012
Southern Power Company and Subsidiary Companies 2012 Annual Report

	2012	2011	2010	2009	2008
Operating Revenues (in thousands):					
Wholesale — non-affiliates	$753,653	$870,607	$752,772	$394,366	$667,979
Wholesale — affiliates	425,180	358,585	370,630	544,415	638,266
Total revenues from sales of electricity	1,178,833	1,229,192	1,123,402	938,781	1,306,245
Other revenues	7,215	6,769	6,939	7,870	7,296
Total	$1,186,048	$1,235,961	$1,130,341	$946,651	$1,313,541
Net Income (in thousands)	$175,285	$162,231	$131,309	$155,852	$144,359
Cash Dividends on Common Stock (in thousands)	$127,000	$91,200	$107,100	$106,100	$94,500
Return on Average Common Equity (percent)	11.72	11.88	10.68	13.36	13.03
Total Assets (in thousands)	$3,779,927	$3,580,977	$3,437,734	$3,043,053	$2,813,140
Gross Property Additions/Plant Acquisitions (in thousands)	$240,692	$254,725	$404,644	$331,289	$49,964
Capitalization (in thousands):					
Common stock equity	$1,522,357	$1,468,682	$1,263,220	$1,195,122	$1,138,361
Long-term debt	1,306,099	1,302,758	1,302,619	1,297,607	1,297,353
Total (excluding amounts due within one year)	$2,828,456	$2,771,440	$2,565,839	$2,492,729	$2,435,714
Capitalization Ratios (percent):					
Common stock equity	53.8	53.0	49.2	47.9	46.7
Long-term debt	46.2	47.0	50.8	52.1	53.3
Total (excluding amounts due within one year)	100.0	100.0	100.0	100.0	100.0
Kilowatt-Hour Sales (in thousands):					
Wholesale — non-affiliates	15,636,986	16,089,875	13,294,455	7,513,569	7,573,713
Wholesale — affiliates	16,373,245	11,773,890	10,494,339	12,293,585	9,402,020
Total	32,010,231	27,863,765	23,788,794	19,807,154	16,975,733
Average Revenue Per Kilowatt-Hour (cents)	3.68	4.41	4.72	4.74	7.69
Plant Nameplate Capacity Ratings (year-end) (megawatts)	8,764	7,908	7,908	7,880	7,555
Maximum Peak-Hour Demand (megawatts):					
Winter	3,018	3,255	3,295	3,224	3,042
Summer	3,641	3,589	3,543	3,308	3,538
Annual Load Factor (percent)	48.6	51.0	54.0	52.6	50.0
Plant Availability (percent)*	92.9	93.9	94.0	96.7	96.0
Source of Energy Supply (percent):					
Gas	91.0	89.2	88.8	84.4	75.6
Alternative (Solar and Biomass)	0.5	0.2	—	—	—
Purchased power —					
From non-affiliates	7.2	6.7	5.5	7.9	11.3

From affiliates	1.3	3.9	5.7	7.7	13.1
Total	100.0	100.0	100.0	100.0	100.0

* Beginning in 2012, plant availability is calculated as a weighted equivalent availability.

PART III

Items 10, 11, 12 (other than the information in paragraph (b) in Item 12), 13, and 14 for Southern Company are incorporated by reference to Southern Company's Definitive Proxy Statement relating to the 2013 Annual Meeting of Stockholders. Specifically, reference is made to "Nominees for Election as Directors," "Corporate Governance," and "Section 16(a) Beneficial Ownership Reporting Compliance" for Item 10, "Executive Compensation," "Compensation Discussion and Analysis," "Compensation and Management Succession Committee Report," "Director Compensation," and "Director Compensation Table" for Item 11, "Stock Ownership Table" for Item 12, "Certain Relationships and Related Transactions" and "Director Independence" for Item 13, and "Principal Public Accounting Firm Fees" for Item 14.

Items 10, 11, 12 (other than the information in paragraph (b) in Item 12), 13, and 14 for Alabama Power, Georgia Power, and Mississippi Power are incorporated by reference to the Definitive Information Statements of Alabama Power, Georgia Power, and Mississippi Power relating to each of their respective 2013 Annual Meetings of Shareholders. Specifically, reference is made to "Nominees for Election as Directors," "Corporate Governance," and "Section 16(a) Beneficial Ownership Reporting Compliance" for Item 10, "Executive Compensation," "Compensation Discussion and Analysis," "Compensation and Management Succession Committee Report," "Director Compensation," and "Director Compensation Table" for Item 11, "Stock Ownership Table" for Item 12, "Certain Relationships and Related Transactions" and "Director Independence" for Item 13, and "Principal Public Accounting Firm Fees" for Item 14.

Items 10, 11, 12, 13, and 14 for Gulf Power are contained herein.

Items 10, 11, 12 and 13 for Southern Power are omitted pursuant to General Instruction I(2)(c) of Form 10-K. Item 14 for Southern Power is contained herein.

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Identification of directors of Gulf Power.

S. W. Connally, Jr.
President and Chief Executive Officer
Age 43
Served as Director since 2012

Allan G. Bense (1)
Age 61
Served as Director since 2010

Deborah H. Calder (1)
Age 52
Served as Director since 2010

William C. Cramer, Jr. (1)
Age 60
Served as Director since 2002

J. Mort O'Sullivan, III (1)
Age 61
Served as Director since 2010

Winston E. Scott (1)
Age 62
Served as Director since 2003

(1) No position other than director.

Each of the above is currently a director of Gulf Power, serving a term running from the last annual meeting of Gulf Power's shareholders (June 26, 2012) for one year until the next annual meeting or until a successor is elected and qualified, except for Mr. Connally whose election was effective July 1, 2012.

There are no arrangements or understandings between any of the individuals listed above and any other person pursuant to which he or she was or is to be selected as a director, other than any arrangements or understandings with directors or officers of Gulf Power acting solely in their capacities as such.

Identification of executive officers of Gulf Power.

S. W. Connally, Jr.
President and Chief Executive Officer
Age 43
Served as Executive Officer since 2012

P. Bernard Jacob
Vice President — Customer Operations
Age 58
Served as Executive Officer since 2003

Richard S. Teel
Vice President and Chief Financial Officer
Age 42
Served as Executive Officer since 2010

Michael L. Burroughs
Vice President — Senior Production Officer
Age 52
Served as Executive Officer since 2010

Bentina C. Terry
Vice President — External Affairs and Corporate Services
Age 42
Served as Executive Officer since 2007

Each of the above is currently an executive officer of Gulf Power, serving a term until the next annual organizational meeting or until a successor is elected and qualified.

There are no arrangements or understandings between any of the individuals listed above and any other person pursuant to which he or she was or is to be selected as an officer, other than any arrangements or understandings with directors or officers of Gulf Power acting solely in their capacities as such.

Identification of certain significant employees. None.

Family relationships. None.

Business experience. Unless noted otherwise, each director has served in his or her present position for at least the past five years.

DIRECTORS

Gulf Power's Board of Directors possesses collective knowledge and experience in accounting, finance, leadership, business operations, risk management, corporate governance, and Gulf Power's industry.

S. W. Connally, Jr. - President and Chief Executive Officer of Gulf Power since July 1, 2012. Mr. Connally previously served as Senior Vice President and Chief Production Officer of Georgia Power from July 2010 through June 2012 and Manager of Alabama Power's Plant Barry from August 2007 through July 2010.

Allan G. Bense - Panama City businessman and former Speaker of the Florida House of Representatives. Mr. Bense is a partner in several companies involved in road building, mechanical contracting, insurance, general contracting, golf courses, and farming and represented the Bay County area in the Florida House of Representatives beginning in 1998 and served as Speaker of the House from 2004 through 2006. Mr. Bense has also served as Vice Chair of Enterprise Florida, the economic development agency for the state, from January 2009 to January 2011.

Deborah H. Calder - Senior Vice President for Navy Federal Credit Union since June 2008. Since September 2007, Ms. Calder has directed the day-to-day operations of more than 2,700 employees and the ongoing construction of Navy Federal Credit Union's campus in the Pensacola area. Ms. Calder has been with Navy Federal Credit Union for over 20 years, serving in previous positions as Vice President of Consumer and Credit Card Lending, Vice President of Collections, Vice President of Call Center Operations, and Assistant Vice President of Credit Cards.

William C. Cramer, Jr. - President and Owner of automobile dealerships in Florida, Georgia, and Alabama.

Mr. Cramer has been an authorized Chevrolet dealer since 1986. In 2009, Mr. Cramer became an authorized dealer of Cadillac, Buick, and GMC vehicles.

J. Mort O'Sullivan, III - Managing Partner of Warren Averett O'Sullivan Creel LLP, an accounting firm originally formed as O'Sullivan Patton Jacobi in 1981. Mr. O'Sullivan currently focuses on consulting and management advisory services to clients, while continuing to offer his expertise in litigation support, business valuations, and mergers and acquisitions. He is a registered investment advisor.

Winston E. Scott - Senior Vice President for External Relations, Florida Institute of Technology since March 2012. He previously served as Dean, College of Aeronautics, Florida Institute of Technology, Melbourne, Florida from August 2008 through March 2012 and Vice President and Deputy General Manager, Engineering and Science Contract Group at Jacobs Engineering, Houston, Texas, from September 2006 through July 2008. Mr. Scott is also a member of the board of directors of Environmental Tectonics Corporation. Mr. Scott's experience also included serving as a pilot in the U.S. Navy, as an astronaut with the National Aeronautic and Space Administration, and as executive director of the Florida Space Authority.

EXECUTIVE OFFICERS

Michael L. Burroughs - Vice President and Senior Production Officer since August 2010. He previously served as Manager of Georgia Power's Plant Yates from September 2007 to July 2010.

P. Bernard Jacob - Vice President of Customer Operations since 2007.

Richard S. Teel - Vice President and Chief Financial Officer since August 2010. He previously served as Vice President and Chief Financial Officer of Southern Company Generation, a business unit of Southern Company, from January 2007 to July 2010.

Bentina C. Terry - Vice President of External Affairs and Corporate Services since 2007.

Involvement in certain legal proceedings. None.

Promoters and Certain Control Persons. None.

Section 16(a) Beneficial Ownership Reporting Compliance. None.

Code of Ethics

The registrants collectively have adopted a code of business conduct and ethics (Code of Ethics) that applies to each director, officer, and employee of the registrants and their subsidiaries. The Code of Ethics can be found on Southern Company's website located at www.southerncompany.com. The Code of Ethics is also available free of charge in print to any shareholder by requesting a copy from Melissa K. Caen, Assistant Secretary, Southern Company, 30 Ivan Allen Jr. Boulevard NW, Atlanta, Georgia 30308. Any amendment to or waiver from the code of ethics that applies to executive officers and directors will be posted on the website.

Corporate Governance

Southern Company has adopted corporate governance guidelines and committee charters. The corporate governance guidelines and the charters of Southern Company's Audit Committee, Compensation and Management Succession Committee, Finance Committee, Governance Committee, and Nuclear/Operations Committee can be found on Southern Company's website located at www.southerncompany.com. The corporate governance guidelines and charters are also available free of charge in print to any shareholder by requesting a copy from Melissa K. Caen, Assistant Secretary, Southern Company, 30 Ivan Allen Jr. Boulevard NW, Atlanta, Georgia 30308.

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Item 11. EXECUTIVE COMPENSATION

GULF POWER
COMPENSATION DISCUSSION AND ANALYSIS (CD&A)
In this CD&A and this Form 10-K, references to the "Compensation Committee" are to the Compensation and Management Succession Committee of the Board of Directors of Southern Company.
This section describes the compensation program for Gulf Power's Chief Executive Officer and Chief Financial Officer in 2012, as well as each of its other three most highly compensated executive officers serving at the end of the year.

S. W. Connally, Jr.	President and Chief Executive Officer
Richard S. Teel	Vice President and Chief Financial Officer
Michael L. Burroughs	Vice President
P. Bernard Jacob	Vice President
Bentina C. Terry	Vice President

Additionally, described is the compensation of Gulf Power's former President and Chief Executive Officer, Mark A. Crosswhite, who is now Executive Vice President and Chief Operating Officer of Southern Company. Collectively, these officers are referred to as the named executive officers.

Executive Summary

Performance

Performance-based pay represents a substantial portion of the total direct compensation paid or granted to the named executive officers for 2012.

	Salary ($)(1)	% of Total	Short-Term Performance Pay ($)(1)	% of Total	Long-Term Performance Pay ($)(1)	% of Total
S. W. Connally, Jr.	295,103	45	226,783	34	136,049	21
R. S. Teel	236,882	48	115,118	23	143,417	29
M. L. Burroughs	187,855	53	91,572	26	75,660	21
P. B. Jacob	253,959	48	120,432	23	152,917	29
B. C. Terry	255,634	48	123,535	23	153,909	29

(1) Salary is the actual amount paid in 2012, Short-Term Performance Pay is the actual amount earned in 2012 based on performance, and Long-Term Performance Pay is the value on the grant date of stock options and performance shares granted in 2012. See the Summary Compensation Table for the amounts of all elements of reportable compensation described in this CD&A.

Gulf Power financial and operational and Southern Company earnings per share (EPS) goal results for 2012 are shown below:

Financial: 46% of Target   Operational: 148% of Target   EPS: 128% of Target

Southern Company's total shareholder return has been:
1-Year: -3.4%   3-Year: 13.9%   5-year: 7.1%

These levels of achievement resulted in payouts that were aligned with Gulf Power and Southern Company performance.

Compensation and Benefit Beliefs

The compensation and benefit program is based on the following beliefs:

- Employees' commitment and performance have a significant impact on achieving business results;
- Compensation and benefits offered must attract, retain, and engage employees and must be financially sustainable;
- Compensation should be consistent with performance: higher pay for higher performance and lower pay for lower performance; and
- Both business drivers and culture should influence the compensation and benefit program.

Based on these beliefs, the Compensation Committee believes that Gulf Power's executive compensation program should:

- Be competitive with the companies in Gulf Power's industry;
- Motivate and reward achievement of Gulf Power's goals;
- Be aligned with the interests of Southern Company's stockholders and Gulf Power's customers; and
- Not encourage excessive risk-taking.

Executive compensation is targeted at the market median of industry peers, but actual compensation is primarily determined by achievement of Gulf Power's business goals. Gulf Power believes that focusing on its customers drives achievement of financial objectives and delivery of a premium, risk-adjusted total shareholder return for Southern Company's stockholders. Therefore, short-term performance pay is based on achievement of Gulf Power's operational and financial performance goals, with one-third determined by operational performance, such as safety, reliability, and customer satisfaction; one-third determined by financial performance; and one-third determined by Southern Company's EPS performance. Long-term performance pay is tied to Southern Company's stockholder value with 40% of the target value awarded in Southern Company stock options, which reward stock price appreciation, and 60% awarded in performance share units, which reward Southern Company's total shareholder return performance relative to that of industry peers and stock price appreciation.

Key Governance and Pay Practices

- Annual pay risk assessment required by the Compensation Committee charter.
- Retention of an independent compensation consultant by the Compensation Committee, Pay Governance LLC, that provides no other services to Gulf Power or Southern Company.
- Inclusion of a claw-back provision that permits the Compensation Committee to recoup performance pay from any employee if determined to have been based on erroneous results, and requires recoupment from an executive officer in the event of a material financial restatement due to fraud or misconduct of the executive officer.
- No excise tax gross-up on change-in-control severance arrangements.
- Provision of limited perquisites and no income tax gross-ups for the Chief Executive Officer except on certain relocation-related benefits.
- "No-hedging" provision in Gulf Power's inside trading policy that is applicable to all employees.
- Strong stock ownership requirements that are being met by all named executive officers.

ESTABLISHING EXECUTIVE COMPENSATION

The Compensation Committee establishes the Southern Company system executive compensation program. In doing so, the Compensation Committee uses information from others, principally its independent compensation consultant, Pay Governance LLC. The Compensation Committee also relies on information from Southern Company's Human Resources staff and, for individual executive officer performance, from Southern Company's and Gulf Power's respective Chief Executive Officers. The role and information provided by each of these sources is described throughout this CD&A.

Consideration of Advisory Vote on Executive Compensation

The Compensation Committee considered the stockholder vote on Southern Company's executive compensation at the 2012 Annual Meeting of Stockholders. In light of the significant support of Southern Company's stockholders (95% of votes cast voting in favor of the proposal) and the actual payout levels of the performance-based compensation program, the Compensation Committee continues to believe that the executive compensation program is competitive and is aligned with financial and operational performance and is in the best interests of Gulf Power's customers and Southern Company's stockholders.

Executive Compensation Focus

The executive compensation program places significant focus on rewarding performance. The program is performance-based in several respects:

- Business unit performance, which includes return on equity (ROE) or net income, and operational performance, compared to target performance levels established early in the year, and EPS determine the actual payouts under the short-term (annual) performance-based compensation program (Performance Pay Program).
- Southern Company Common Stock (Common Stock) price changes result in higher or lower ultimate values of stock options.
- Southern Company total shareholder return compared to those of industry peers leads to higher or lower payouts under the Performance Share Program (performance shares).

In support of this performance-based pay philosophy, Gulf Power has no general employment contracts or guaranteed severance with the named executive officers, except upon a change in control. The pay-for-performance principles do not only apply to the named executive officers. The Performance Pay Program covers almost all of the 1,400 employees of Gulf Power. Stock options and performance shares are granted to nearly 125 employees of Gulf Power. These programs engage employees, which ultimately is good not only for them, but also for Gulf Power's customers and Southern Company's stockholders.

OVERVIEW OF EXECUTIVE COMPENSATION COMPONENTS

The primary components of the 2012 executive compensation program are shown below:

Gulf Power’s executive compensation program consists of a combination of short-term and long-term components. Short-term compensation includes base salary and the Performance Pay Program. Long-term compensation includes stock options and performance shares. The performance-based compensation components are linked to financial and operational performance, stock performance, and Southern Company's total shareholder return. The executive compensation program is approved by the Compensation Committee, which consists entirely of independent directors. The Compensation Committee believes that the executive compensation program is a balanced program that provides market-based compensation and motivates and rewards performance.

ESTABLISHING MARKET-BASED COMPENSATION LEVELS

For the named executive officers, the Compensation Committee and Southern Company Human Resources staff review compensation data from large, publicly-owned electric and gas utilities. The data was developed and analyzed by Pay Governance LLC, the independent compensation consultant retained by the Compensation Committee. The companies included each year in the primary peer group are those whose data is available through the consultant’s database. Those companies are drawn from this list of primarily regulated utilities of $2 billion in revenues and up.

Alliant Energy Corporation	First Solar Inc.	Pinnacle West Capital Corporation
Ameren Corporation	GenOn Energy, Inc.	PPL Corporation
American Electric Power Company, Inc.	GDF SUEZ Energy North America, Inc.	Progress Energy, Inc.
Atmos Energy Corporation	Iberdrola, S.A.	Public Service Enterprise Group Inc.
Bg US Services, Inc.	Integrys Energy Group, Inc.	Puget Energy, Inc.
Calpine Corporation	Invensys plc	Salt River Project
CenterPoint Energy, Inc.	Kinder Morgan Energy Partners, L.P.	SCANA Corporation
CMS Energy Corporation	LG&E and KU Energy LLC	Sempra Energy
Consolidated Edison, Inc.	McDermott International, Inc.	Southern Union Company
Constellation Energy Group, Inc.	MDU Resources Group, Inc.	Spectra Energy Corp.
CPS Energy	MidAmerican Energy Company	Targa Resources Partners LP
Crosstex Energy, Inc.	National Grid USA	TECO Energy, Inc.
Dominion Resources, Inc.	New York Power Authority	Tennessee Valley Authority
DTE Energy Company	NextEra Energy, Inc.	The AES Corporation
Duke Energy Corporation	Nicor Inc.	The Babcock & Wilcox Company
Edison International	Northeast Utilities	The Williams Companies, Inc.
El Paso Corporation	NRG Energy, Inc.	TransCanada Corporation
Enbridge Energy Partners, LP	NSTAR	UGI Corporation
Energy Future Holdings Corp.	NV Energy, Inc.	Vectren Corporation
Entergy Corporation	OGE Energy Corp.	Westar Energy, Inc.
Enterprise Products Partners L.P.	Oncor Electric Delivery Company LLC	Wisconsin Energy Corporation
Exelon Corporation	Pepco Holdings, Inc.	Xcel Energy Inc.
FirstEnergy Corp.		

Market data for the chief executive officer position and other positions in terms of scope of responsibilities that most closely resemble the positions held by the named executive officers is reviewed. When appropriate, the market data is size-adjusted, up or down, to accurately reflect comparable scopes of responsibility. Based on the data, a total target compensation opportunity is established for each named executive officer. Total target compensation opportunity is the sum of base salary, annual performance-based compensation at a target performance level, and long-term performance-based compensation (stock options and performance shares) at a target value. Actual compensation paid may be more or less than the total target compensation opportunity based on actual performance above or below target performance levels. As a result, the compensation program is designed to result in payouts that are market-appropriate given Gulf Power’s and Southern Company’s performance for the year or period. A specified weight was not targeted for base salary or annual or long-term performance-based compensation as a percentage of total target compensation opportunities, nor did amounts realized or realizable from prior compensation serve to increase or decrease 2012 compensation amounts. Total target compensation opportunities for senior management as a group, including the named executive officers, are managed to be at the median of the market for companies of similar size in the electric utility industry. Therefore, some executives may be paid above and others below market. This practice allows for differentiation based on time in the position, scope of responsibilities, and individual performance. The differences in the total pay opportunities for each named executive officer are based almost exclusively on the differences indicated by the market data for persons holding similar positions. Because of the use of market data from a large number of industry peer companies for positions that are not identical in terms of scope of responsibility from company to company, minor differences are not considered to be material and the compensation program is believed to be market-appropriate, as long as senior management as a group is within an appropriate range. Generally, compensation is considered to be within an appropriate range if it is not more or less than 15% of the applicable market data. The total target compensation opportunity was established in early 2012 for each named executive officer below:

	Salary ($)	Target Annual Performance-Based Compensation ($)	Target Long-Term Performance-Based Compensation ($)	Total Target Compensation Opportunity ($)
S. W. Connally, Jr.	226,752	102,038	136,049	464,839
M. A. Crosswhite	411,529	246,917	534,966	1,193,412
R. S. Teel	239,082	107,587	143,417	490,086
M. L. Burroughs	189,199	75,680	75,660	340,539
P. B. Jacob	254,882	114,697	152,917	522,496
B. C. Terry	256,563	115,453	153,909	525,925

The salary levels shown above were not effective until March 2012. Therefore, the salary amounts reported in the Summary Compensation Table are different than the amounts shown above because that table reports actual amounts paid in 2012.
Until July 1, 2012, Mr. Connally served as Senior Vice President of Southern Company Generation and Georgia Power and Mr. Crosswhite served as Chief Executive Officer of Gulf Power. Both Messrs. Connally and Crosswhite received promotions at that time resulting in increases in salary to $361,250 and $488,750, respectively, and increases in target annual performance-based compensation to $216,750 and $342,125, respectively.

For purposes of comparing the value of the compensation program to the market data, stock options are valued at $3.39 per option and performance shares at $41.99 per unit. These values represent risk-adjusted present values on the date of grant and are consistent with the methodologies used to develop the market data. The mix of stock options and performance shares granted were 40% and 60%, respectively, of the long-term value shown above.

In 2011, Pay Governance LLC analyzed the level of actual payouts for 2010 performance under the annual Performance Pay Program to the named executive officers relative to performance versus peer companies to provide a check on the goal-setting process, including goal levels and associated performance-based pay opportunities. The findings from the analysis were used in establishing performance goals and the associated range of payouts for goal achievement for 2012. That analysis was updated in 2012 by Pay Governance LLC for 2011 performance, and those findings were used in establishing goals for 2013.

DESCRIPTION OF KEY COMPENSATION COMPONENTS

2012 Base Salary

Most employees, including all of the named executive officers, received base salary increases in 2012.

With the exception of Southern Company executive officers, base salaries for all Southern Company system officers are within a position level with a base salary range that is established by Southern Company Human Resources staff using the market data described above. Each officer is within one of these established position levels based on the scope of responsibilities that most closely resemble the positions included in the market data described above. The base salary level for individual officers is set within the applicable pre-established range. Factors that influence the specific base salary level within the range include the need to retain an experienced team, internal equity, time in position, and individual performance. Individual performance includes the degree of competence and initiative exhibited and the individual's relative contribution to the results of operations in prior years. Base salaries are reviewed annually in February and changes are made effective March 1. The base salary levels established early in the year for the named executive officers were set within the applicable position level salary range and were recommended by the individual named executive officer's superior and approved by Southern Company's Chief Executive Officer. Mr. Crosswhite's and Mr. Connally's base salaries that were increased effective July 1, 2012 were approved by the Compensation Committee.

2012 Performance-Based Compensation

This section describes performance-based compensation for 2012.

Achieving Operational and Financial Performance Goals — The Guiding Principle for Performance-Based Compensation

The Southern Company system's number one priority is to continue to provide customers outstanding reliability and superior service at reasonable prices while achieving a level of financial performance that benefits Southern Company's stockholders in the short and long term. Operational excellence and business unit and Southern Company financial performance are integral to the achievement of business results that benefit customers and stockholders.

Therefore, in 2012, Gulf Power strove for and rewarded:

- Continuing industry-leading reliability and customer satisfaction, while maintaining reasonable retail prices; and
- Meeting energy demand with the best economic and environmental choices.

In 2012, Gulf Power also focused on and rewarded:

- EPS growth;
- ROE – target performance level in the top quartile of comparable electric utilities;
- Southern Company dividend growth;
- Long-term, risk-adjusted total shareholder return; and
- Financial integrity — an attractive risk-adjusted return, sound financial policy, and a stable "A" credit rating.

The performance-based compensation program is designed to encourage achievement of these goals. The Southern Company Chief Executive Officer, with the assistance of Southern Company's Human Resources staff, recommended to the Compensation Committee the program design and award amounts for senior management, including the named executive officers.

2012 Annual Performance-Based Pay Program

Annual Performance Pay Program Highlights
Rewards achievement of annual goals:
EPS
Business unit financial performance (ROE or net income)
Business unit operational performance
Goals are weighted one-third each
Performance results range from 0% to 200% of target, based on level of goal achievement

Overview of Program Design

Almost all employees of Gulf Power, including the named executive officers, are participants.

The performance goals are set at the beginning of each year by the Compensation Committee.

- For Southern Company's traditional operating companies, including Gulf Power, operational goals are safety, customer satisfaction, plant availability, transmission and distribution system reliability, and culture. For the nuclear operating company, Southern Nuclear, operational goals are safety, plant operations, and culture. Each of these operational goals is explained in more detail under Goal Details below. The level of achievement for each operational goal is determined according to the respective performance schedule, and the total operational goal performance is determined by the weighted average result. Each business unit has its own operational goals.

- EPS is defined as Southern Company's earnings from continuing operations divided by average shares outstanding during the year. The EPS performance measure is applicable to all participants in the Performance Pay Program.

For Southern Company's traditional operating companies, including Gulf Power, the business unit financial performance goal is ROE, which is defined as the traditional operating company's net income divided by average equity for the year. For Southern Power, the business unit financial performance goal is net income, excluding net income from acquisitions.

The Compensation Committee may make adjustments, both positive and negative, to goal achievement for purposes of determining payouts. For the financial performance goals, such adjustments could include the impact of items considered non-recurring or outside of normal operations or not anticipated in the business plan when the EPS goal was established and of sufficient magnitude to warrant recognition. The EPS goal results were decreased two cents per share to exclude the impact of an insurance recovery related to the MC Asset Recovery, LLC (MCAR) litigation settlement. This reduction decreased average payouts approximately 7%. The Compensation Committee believed this adjustment was necessary because EPS goal results were increased in 2009 by the amount of the MCAR litigation settlement. For Messrs. Connally, Crosswhite, and Jacob, the safety goal achievement level was reduced by 20% for purposes of calculating their respective payouts under the Performance Pay Program because there was a work-related fatality in 2012 at Gulf Power. The reduction was approved by the Compensation Committee. This reduction is reflected in the total performance factor reported on page III-14 of this CD&A. Additionally, under the terms of the program, no payout can be made if Southern Company's current earnings are not sufficient to fund the Common Stock dividend at the same level or higher than the prior year.

Goal Details

Operational Goals	Description	Why It Is Important
Customer Satisfaction	Customer satisfaction surveys evaluate performance. The survey results provide an overall ranking for each traditional operating company, including Gulf Power, as well as a ranking for each customer segment: residential, commercial, and industrial.	Customer satisfaction is key to operations. Performance of all operational goals affect customer satisfaction.
Reliability	Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on recent historical performance.	Reliably delivering power to customers is essential to Gulf Power's operations.
Availability	Peak season equivalent forced outage rate is an indicator of availability and efficient generation fleet operations during the months when generation needs are greatest. Availability is measured as a percentage of the hours of forced outages out of the total generation hours.	Availability of sufficient power during peak season fulfills the obligation to serve and provide customers with the least cost generating resources.
Nuclear Plant Operations	Nuclear plant performance is evaluated by measuring nuclear safety as rated by independent industry evaluators, as well as by a quantitative score comprised of various plant performance indicators. Plant reliability and operational availability is measured as a percentage of time the nuclear plant is operating, and accommodates generation reductions associated with planned outages. In addition, a subjective assessment of progress on the construction and licensing of Georgia Power's two new nuclear units, Plant Vogtle Units 3 and 4, is also in place.	Safe and efficient operation of the nuclear fleet is important for delivering clean energy at a reasonable price.
Safety	Southern Company's Target Zero program is focused on continuous improvement in having a safe work environment. The performance	Essential for the protection of employees, customers,

	is measured by the applicable company's ranking, as compared to peer utilities in the Southeastern Electric Exchange.	and communities.
Culture	The culture goal seeks to improve Gulf Power's inclusive workplace. This goal includes measures for work environment (employee satisfaction survey), representation of minorities and females in leadership roles (subjectively assessed), and supplier diversity.	Supports workforce development efforts and helps to assure diversity of suppliers.

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Financial Performance Goals	Description	Why It Is Important
EPS	Southern Company's earnings from continuing operations divided by average shares outstanding during the year.	Supports commitment to provide Southern Company's stockholders solid risk-adjusted returns.
Business Unit ROE/Net Income	For the traditional operating companies, including Gulf Power, the business unit financial performance goal is ROE, which is defined as the applicable company's net income divided by average equity for the year. For Southern Power, the business unit financial performance goal is net income, excluding income from acquisitions.	Supports delivery of Southern Company stockholder value and contributes to Gulf Power's and Southern Company's sound financial policies and stable credit ratings.

The ranges of performance levels established for the primary operational goals are detailed below.

Level of Performance	Customer Satisfaction	Reliability	Availability	Nuclear Plant Operations	Safety	Culture
Maximum	Top quartile for all customer segments and overall	Significantly exceed target	Industry best	Significantly exceed targets	Greater than top 20th percentile and company best	Significant improvement
Target	Top quartile overall	Meet target	Top quartile	Meet targets	Top 40th percentile	Improvement
Threshold	2nd quartile overall	Significantly below target	2nd quartile	Significantly below targets	Top 60th percentile	Significantly below expectations

The Compensation Committee approves specific objective performance schedules to calculate performance between the threshold, target, and maximum levels for each of the operational goals. If goal achievement is below threshold, there is no payout associated with the applicable goal.

EPS and Business Unit Financial Performance:

The range of EPS, business unit ROE, and Southern Power net income goals for 2012 is shown below. ROE goals vary from the allowed retail ROE range due to state regulatory accounting requirements, wholesale activities, other non-jurisdictional revenues and expenses, and other activities not subject to state regulation.

Level of Performance	EPS ($)	ROE (%)	Southern Power Net Income ($) (millions) (1)
Maximum	2.77	14.0	195
Target	2.64	12.0	155
Threshold	2.51	10.0	115

(1) Excluding income from acquisitions.

For 2012, the Compensation Committee established a minimum EPS performance threshold that must be achieved. If EPS was less than $2.38 (90% of Target), not only would there have been no payout associated with EPS performance, but overall payouts under the Performance Pay Program would have been reduced by 10% of target. In setting the goals for pay purposes, the Compensation Committee relies on information on financial and operational goals from the Finance Committee and the Nuclear/Operations Committee of Southern Company's Board of Directors, respectively.

2012 Achievement

Each named executive officer had a target Performance Pay Program opportunity, based on his or her position, set by the Compensation Committee at the beginning of 2012. Targets are set as a percentage of base salary. Mr. Connally's target was initially set at 45% and increased to 60% effective July 1, 2012. Mr. Crosswhite's was initially set at 60% and increased to 70% effective July 1, 2012. For Ms. Terry and Messrs. Jacobs and Teel, the targets were set at 45% each and, for Mr. Burroughs, it was set at 40%. Actual payouts were determined by adding the payouts derived from EPS and applicable business unit operational and financial performance goal achievement for 2012 and dividing by three. EPS exceeded the minimum threshold established and therefore payouts were not affected. Actual 2012 goal achievement is shown in the following tables.

Operational Goal Results:

Gulf Power	Achievement Percentage
Customer Satisfaction	133
Reliability	100
Availability	200
Safety	138
Culture	152

Corporate/Southern Company Generation	Achievement Percentage
Customer Satisfaction	167
Reliability	174
Availability	170
Safety	200
Culture (Corporate/Southern Company Generation)	138/146

Georgia Power	Achievement Percentage
Customer Satisfaction	167
Reliability	171
Availability	77
Safety	163
Culture	141

Southern Nuclear	Achievement Percentage
Nuclear Safety	160
Nuclear Reliability	200
Vogtle Units 3 and 4 Assessment	150
Culture	139

Overall, the levels of achievement shown above resulted in an operational goal performance factor for Corporate, Gulf Power, Georgia Power, Southern Company Generation, and Southern Nuclear of 169%, 148%, 143%, 171%, and 157% respectively.

Financial Performance Goal Results:

Goal	Result	Achievement Percentage
EPS (excluding MCAR insurance recovery)	$2.67	128

Gulf Power ROE	10.92%	46
Georgia Power ROE	12.76%	138
Aggregate ROE	12.55%	122
Southern Power Net Income (excluding $4.5 million from acquisitions)	$171 million	189

Calculating Payouts:

All of the named executive officers are paid based on EPS performance. Ms. Terry and Messrs. Jacob and Teel were employed by Gulf Power for all of 2012 and therefore their annual Performance Pay Program payout is calculated using ROE and operational goal achievement of Gulf Power. Mr. Connally was employed by Gulf Power and Southern Company Generation (supporting Georgia Power) during 2012 and therefore his payout is prorated based on goal achievement for Gulf Power and Southern Company Generation, based on the period of service with each. Mr. Crosswhite was employed by Gulf Power prior to becoming an executive officer of Southern Company and therefore his payout is prorated based on goal achievement for Gulf Power and the corporate/aggregate goal results, based on the period of service with each. Mr. Burroughs was employed by Southern Company Generation (supporting Gulf Power) during 2012. Southern Company Generation officers are paid based on the goal achievement of the traditional operating company supported (60%) and Southern Company Generation (40%). With the exception of the culture goal, Southern Company Generation's operational goal results are the corporate/aggregate results.

A total performance factor is determined by adding the EPS and applicable business unit financial and operational goal performance results and dividing by three. The total performance factor is multiplied by the target Performance Pay Program opportunity, as described above, to determine the payout for each named executive officer.

The table below shows the pay opportunity at target-level performance and the actual payout based on the actual performance shown above.

	Target Annual Performance Pay Program Opportunity ($)	Total Performance Factor (%)	Actual Annual Performance Pay Program Payout ($)
S. W. Connally, Jr.	189,927	119	226,783
M. A. Crosswhite	317,932	125	397,755
R. S. Teel	107,587	107	115,118
M. L. Burroughs	75,680	121	91,572
P. B. Jacob	114,697	105	120,432
B. C. Terry	115,453	107	123,535

Long-Term Performance-Based Compensation

2012 Long-Term Pay Program Highlights

Stock Options:

§ Reward long-term Common Stock price appreciation
§ Represent 40% of long-term target value
§ Vest over three years
§ Ten-year term

Performance Shares:

§ Reward total shareholder return relative to industry peers and stock price appreciation
§ Represent 60% of long-term target value
§ Three-year performance period
§ Performance results can range from 0% to 200% of target
§ Paid in Common Stock at end of performance period

Long-term performance-based awards are intended to promote long-term success and increase Southern Company's stockholder value by directly tying a substantial portion of the named executive officers' total compensation to the interests of Southern Company's stockholders. The long-term awards provide an incentive to grow Southern Company's stockholder value.

Stock options represent 40% of the long-term performance target value and performance shares represent the remaining 60%. The Compensation Committee elected this mix because it concluded that doing so represented an appropriate balance between incentives. Stock options only generate value if the price of the stock appreciates after the grant date, and performance shares reward employees based on Southern Company total shareholder return relative to industry peers, as well as Common Stock price.

The following table shows the grant date fair value of the long-term performance-based awards in total and each component awarded in 2012.

	Value of Options ($)	Value of Performance Shares ($)	Total Long-Term Value ($)
S. W. Connally, Jr.	54,420	81,629	136,049
M. A. Crosswhite	213,994	320,972	534,966
R. S. Teel	57,379	86,038	143,417
M. L. Burroughs	30,269	45,391	75,660
P. B. Jacob	61,169	91,748	152,917
B. C. Terry	61,573	92,336	153,909

Stock Options

Stock options granted have a 10-year term, vest over a three-year period, fully vest upon retirement or termination of employment following a change in control, and expire at the earlier of five years from the date of retirement or the end of the 10-year term. For the grants made in 2012, unvested options are forfeited if the named executive officer retires from the Southern Company system and accepts a position with a peer company within two years of retirement. The value of each stock option was derived using the Black-Scholes stock option pricing model. The assumptions used in calculating that amount are discussed in Note 8 to the financial statements of Gulf Power in Item 8 herein. For 2012, the Black-Scholes value on the grant date was $3.39 per stock option.

Performance Shares

2012-2014 Grant

Performance shares are denominated in units, meaning no actual shares are issued on the grant date. A grant date fair value per unit was determined. For the grant made in 2012, the value per unit was $41.99. See the Summary Compensation Table and the information accompanying it for more information on the grant date fair value. The total target value for performance share units is divided by the value per unit to determine the number of performance share units granted to each participant, including the named executive officers. Each performance share unit represents one share of Common Stock. At the end of the three-year performance period (January 1, 2012 through December 31, 2014), the number of units will be adjusted up or down (0% to 200%) based on Southern Company's total shareholder return relative to that of its peers in the Philadelphia Utility Index and the Southern Company custom peer group. The companies in the custom peer group are those that are believed to be most similar to Southern Company in both business model and investors. The Philadelphia Utility Index was chosen because it is a published index and, because it includes a larger number of peer companies, it can mitigate volatility in results over time, providing an appropriate level of balance. The peer groups vary from the Market Data peer group (as listed on page III-8) due to the timing and criteria of the peer selection process; however, there is significant overlap. The results of the two peer groups will be averaged. The number of performance share units earned will be paid in Common Stock at the end of the three-year performance period. No dividends or dividend equivalents will be paid or earned on the performance share units.

The companies in the Philadelphia Utility Index on the grant date are listed below.

Ameren Corporation	Entergy Corporation
American Electric Power Company, Inc.	Exelon Corporation

CenterPoint Energy, Inc.
Consolidated Edison, Inc.
Covanta Holding Corporation
Dominion Resources, Inc.
DTE Energy Company
Duke Energy Corporation
Edison International
El Paso Electric Company
FirstEnergy Corp.
NextEra Energy, Inc.
Northeast Utilities
PG&E Corporation
Public Service Enterprise Group Inc.
The AES Corporation
Xcel Energy Inc.

The companies in the custom peer group on the grant date are listed below.

Alliant Energy Corporation	NSTAR
American Electric Power Company, Inc.	PG&E Corporation
CMS Energy Corporation	Pinnacle West Capital Corporation
Consolidated Edison, Inc.	Progress Energy, Inc.
DTE Energy Company	SCANA Corporation
Duke Energy Corporation	Wisconsin Energy Corporation
Edison International	Xcel Energy Inc.
Northeast Utilities	

The scale below will determine the number of units paid in Common Stock following the last year of the performance period, based on the 2012 through 2014 performance period. Payout for performance between points will be interpolated on a straight-line basis.

Performance vs. Peer Group	Payout (% of Each Performance Share Unit Paid)
90th percentile or higher	200
50th percentile (Target)	100
10th percentile or lower	0

Performance shares are not earned until the end of the three-year performance period. A participant who terminates, other than due to retirement or death, forfeits all unearned performance shares. Participants who retire or die during the performance period only earn a prorated number of units, based on the number of months they were employed during the performance period.

2010-2012 Payouts

The first performance share grants were made in 2010 with a three-year performance period that ended on December 31, 2012. Based on Southern Company's total shareholder return achievement relative to that of the Philadelphia Utility Index (152.5%) and the customer peer group (117.5%), the payout percentage was 135% of target. The following table shows the target and actual awards of performance shares for the named executive officers.

	Target Performance Shares (#)	Performance Shares Earned (#)
S. W. Connally, Jr.	1,472	1,987
M. A. Crosswhite	4,280	5,778
R. S. Teel	1,568	2,117
M. L. Burroughs	401	541
P. B. Jacob	2,848	3,845
B. C. Terry	2,824	3,812

Performance Dividends

The Compensation Committee terminated the Performance Dividend Program in 2010. The value of performance dividends represented a significant portion of long-term performance-based compensation that was awarded prior to 2010. At target performance levels, performance dividends represented up to 65% of the total long-term value granted over the 10-year term of stock options. Therefore, because performance dividends were awarded for years prior to

2010, in fairness to participants, the outstanding performance dividend awards were not cancelled. The Compensation Committee approved a three-year transition period, beginning with the 2007 through 2010 performance-measurement period, to continue to pay performance dividends, if earned, on stock options that were granted prior to 2010. The grant of performance shares, described above, replaced performance dividend awards beginning in 2010. Therefore, the final payout of performance dividends was made on stock options granted prior to 2010 that were outstanding at the end of the four-year performance-measurement period that ended on December 31, 2012, as reported in the Summary Compensation Table. Because performance shares are earned at the end of a three-year performance period, both the last award of performance dividends and the first award of performance shares were earned at the end of 2012. Performance dividends range from 0% to 100% of the Common Stock dividend paid during the year per eligible stock option held at the end of the performance-measurement period. Actual payout depended on Southern Company's total shareholder return over a four-year performance-measurement period compared to a group of other electric and gas utility companies, as selected at the beginning of the performance-measurement period. The Compensation Committee selected a custom peer group and the Philadelphia Utility Index for the 2009-2012 grant. Total shareholder return is calculated by measuring the ending value of a hypothetical $100 invested in each custom peer group company's common stock and in the Philadelphia Utility Index at the beginning of each of 16 quarters. In the final year of the performance-measurement period, Southern Company's ranking in the peer groups is determined at the end of each quarter and the percentile ranking is multiplied by the actual Common Stock dividend paid in that quarter. To determine the total payout per stock option held at the end of the performance-measurement period, the four quarterly amounts earned are added together.

No performance dividends are paid if Southern Company's earnings are not sufficient to fund a Common Stock dividend at least equal to that paid in the prior year.

2012 Payout

The peer groups used to determine the 2012 payout for the 2009 through 2012 performance-measurement period consisted of the Philadelphia Utility Index and a custom peer group. See the discussion on page III-7 of this CD&A for more information about the selection of the peer groups.

The scale below determined the percentage of each quarter's dividend paid in the last year of the performance-measurement period to be paid on each eligible stock option held at December 31, 2012, based on performance during the 2009 through 2012 performance-measurement period. Payout for performance between points was interpolated on a straight-line basis.

Performance vs. Peer Group	Payout (% of Each Performance Share Unit Paid)
90th percentile or higher	100
50th percentile (Target)	50
10th percentile or lower	0

Southern Company's relative total shareholder return performance, as measured at the end of each quarter of the final year of the four-year performance-measurement period, resulted in a total payout of 70% of the target level (35% of the full year's Common Stock dividend), or $0.68. This amount was multiplied by each named executive officer's eligible outstanding stock options as of December 31, 2012 to calculate the payout under the program. The amount paid is included in the Non-Equity Incentive Plan Compensation column in the Summary Compensation Table.

Timing of Performance-Based Compensation

As discussed above, the 2012 annual Performance Pay Program goals and the total shareholder return goals applicable to performance shares were established early in the year by the Compensation Committee. Annual stock option grants also were made at that meeting. The establishment of performance-based compensation goals and the granting of stock options were not timed with the release of material, non-public information. This procedure is consistent with prior practices. Stock option grants are made to new hires or newly-eligible participants on preset, regular quarterly dates that were approved by the Compensation Committee. The exercise price of options granted to employees in 2012 was the closing price of the Common Stock on the grant date or the last trading day before the grant date, if the grant date was not a trading day.

Retirement and Severance Benefits

Certain post-employment compensation is provided to employees, including the named executive officers.

Retirement Benefits

Generally, all full-time employees of Gulf Power participate in the funded Pension Plan after completing one year of service. Normal retirement benefits become payable when participants attain age 65 and complete five years of participation. Gulf Power also provides unfunded benefits that count salary and annual Performance Pay Program payouts that are ineligible to be counted under the Pension Plan. See the Pension Benefits table and accompanying information for more pension-related benefits information. Gulf Power also provides supplemental retirement benefits to certain employees that were first employed

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by Gulf Power, or an affiliate of Gulf Power, in the middle of their careers. Gulf Power has a supplemental retirement agreement (SRA) with both Ms. Terry and Mr. Crosswhite. Prior to their employment, Ms. Terry and Mr. Crosswhite provided legal services to Southern Company's subsidiaries. Ms. Terry's agreement provides retirement benefits as if she was employed an additional 10 years and Mr. Crosswhite's provides an additional 15 years of benefits. Ms. Terry must remain employed at Gulf Power or an affiliate of Gulf Power for 10 years from the effective date of the SRA, before vesting in the benefits. Mr. Crosswhite is vested in the benefits. These agreements provide a benefit which recognizes the expertise both brought to Gulf Power and they provide a strong retention incentive to remain with Gulf Power, or one of its affiliates, for the vesting period and beyond. Gulf Power also provides the Deferred Compensation Plan which is an unfunded plan that permits participants to defer income as well as certain federal, state, and local taxes until a specified date or their retirement, disability, death, or other separation from service. Up to 50% of base salary and up to 100% of performance-based non-equity compensation may be deferred at the election of eligible employees. All of the named executive officers are eligible to participate in the Deferred Compensation Plan. See the Nonqualified Deferred Compensation table and accompanying information for more information about the Deferred Compensation Plan.

Change-in-Control Protections

Change-in-control protections, including severance pay and, in some situations, vesting or payment of long-term performance-based awards, are provided upon a change in control of Southern Company or Gulf Power coupled with an involuntary termination not for cause or a voluntary termination for “Good Reason.” This means there is a “double trigger” before severance benefits are paid; i.e., there must be both a change in control and a termination of employment. Severance payment amounts are two times salary plus target Performance Pay Program opportunity for Messrs. Connally and Crosswhite and one times salary plus Performance Pay Program opportunity for the other named executive officers. No excise tax gross-up would be provided. More information about severance arrangements is included in the section entitled Potential Payments upon Termination or Change-in-Control.

Perquisites

Gulf Power provides limited perquisites to its executive officers, including the named executive officers. The perquisites provided in 2012, including amounts, are described in detail in the information accompanying the Summary Compensation Table. No tax assistance is provided on perquisites for Southern Company executive officers, including Mr. Crosswhite and, after June 30, 2012, Mr. Connally, except on certain relocation-related benefits.

EXECUTIVE STOCK OWNERSHIP REQUIREMENTS

Officers of Gulf Power that are in a position of Vice President or above are subject to stock ownership requirements. All of the named executive officers are covered by the requirements. Ownership requirements further align the interest of officers and Southern Company’s stockholders by promoting a long-term focus and long-term share ownership. The types of ownership arrangements counted toward the requirements are shares owned outright, those held in Southern Company-sponsored plans, and Common Stock accounts in the Deferred Compensation Plan and the Supplemental Benefit Plan. One-third of vested stock options may be counted, but, if so, the ownership requirement is doubled. The ownership requirement is reduced by one-half at age 60.

The requirements are expressed as a multiple of base salary as shown below.

	Multiple of Salary without Counting Stock Options	Multiple of Salary Counting 1/3 of Vested Options
S. W. Connally, Jr.	3 Times	6 Times
M. A. Crosswhite	3 Times	6 Times

R. S. Teel	2 Times	4 Times
M. L. Burroughs	1 Times	2 Times
P. B. Jacob	2 Times	4 Times
B. C. Terry	2 Times	4 Times

Newly-elected officers have approximately five years from the date of their election to meet the applicable ownership requirement and newly-promoted officers, including Messrs. Connally and Crosswhite, have approximately five years from the date of their promotion to meet the increased ownership requirements. All of the named executive officers are meeting their respective ownership requirement.

POLICY ON RECOVERY OF AWARDS

Southern Company's Omnibus Incentive Compensation Plan provides that, if Southern Company or Gulf Power is required to prepare an accounting restatement due to material noncompliance as a result of misconduct, and if an executive officer of Gulf Power knowingly or grossly negligently engaged in or failed to prevent the misconduct or is subject to automatic forfeiture under the Sarbanes-Oxley Act of 2002, the executive officer will reimburse the amount of any payment in settlement of awards earned or accrued during the 12-month period following the first public issuance or filing that was restated.

POLICY REGARDING HEDGING THE ECONOMIC RISK OF STOCK OWNERSHIP

Southern Company's policy is that employees and outside directors will not trade Southern Company options on the options market and will not engage in short sales.

COMPENSATION COMMITTEE REPORT

The Compensation Committee met with management to review and discuss the CD&A. Based on such review and discussion, the Compensation Committee recommended to the Southern Company Board of Directors that the CD&A be included in the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2012. The Southern Company Board of Directors approved that recommendation.

Members of the Compensation Committee:

Veronica M. Hagen, Chair
Henry A. Clark III
H. William Habermeyer, Jr.
William G. Smith, Jr.

SUMMARY COMPENSATION TABLE

The Summary Compensation Table shows the amount and type of compensation received or earned in 2010, 2011, and 2012 by the named executive officers, except as noted below.

Name and Principal Position (a)	Year (b)	Salary ($) (c)	Bonus ($) (d)	Stock Awards ($) (e)	Option Awards ($) (f)	Non-Equity Incentive Plan Compensation ($) (g)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($) (h)	All Other Compensation ($) (i)	Total ($) (j)
S. W. Connally, Jr. President, Chief Executive Officer, and Director	2012	295,103	24,376	81,629	54,420	249,526	431,809	179,308	1,316,171
M. A. Crosswhite Executive Vice President and Chief	2012	446,442	41,153	320,972	213,994	468,323	790,434	863,157	3,144,475
Operating Officer of Southern Company	2011	395,937	38,791	311,608	207,760	384,016	366,993	480,990	2,186,095
R. S. Teel Vice President and	2012	236,882	—	86,038	57,379	143,335	118,474	15,610	657,718
Chief Financial Officer	2011	225,993	—	81,760	54,516	156,624	72,473	14,773	606,139
	2010	205,540	22,056	47,244	31,508	171,316	50,082	448,620	976,366
M. L. Burroughs	2012	187,855	—	45,391	30,269	94,634	204,035	12,218	574,402
Vice President	2011	180,684	—	43,632	29,107	102,255	135,314	49,366	540,358
	2010	150,745	24,612	12,082	8,073	95,255	94,324	220,820	605,911
P. B. Jacob	2012	253,959	—	91,748	61,169	145,616	310,532	16,671	879,695
Vice President	2011	249,188	—	89,925	59,969	159,207	233,428	15,714	807,431
	2010	239,444	—	85,810	57,217	172,892	176,201	19,021	750,585
B. C. Terry	2012	255,634	—	92,336	61,573	159,332	210,941	16,910	796,726
Vice President	2011	250,194	—	90,536	60,366	182,994	122,604	15,957	722,651
	2010	237,466	—	85,087	56,742	183,929	259,023	22,542	844,789

Column (a)

Mr. Connally was not an executive officer of Gulf Power prior to 2012, and Mr. Crosswhite was not an executive officer of Gulf Power prior to 2011. Mr. Crosswhite served as President and Chief Executive Officer of Gulf Power through June 2012.

Column (d)

The amounts shown for 2012 for Messrs. Connally and Crosswhite are geographic relocation incentives that were paid in connection with their relocations. The relocation incentive equaled 10% of salary rate as of the date of relocation.

Column (e)

This column does not reflect the value of stock awards that were actually earned or received in 2012. Rather, as required by applicable rules of the SEC, this column reports the aggregate grant date fair value of performance shares granted in 2012. The value reported is based on the probable outcome of the performance conditions as of the grant date, using a Monte Carlo simulation model. No amounts will be earned until the end of the three-year performance period on December 31, 2014. The value then can be earned based on performance ranging from 0 to 200%, as established by the Compensation Committee. The aggregate grant date fair value of the performance shares granted in 2012 to Ms. Terry and Messrs. Connally, Crosswhite, Teel, Burroughs, and Jacob, assuming the highest level of performance is achieved, is $184,672, $163,257, $641,943, $172,075, $90,782, and $183,496, respectively (200% of the amount shown in the table). See Note 8 to the financial statements of Gulf Power in Item 8 herein for a discussion of the assumptions used in calculating these amounts.

Column (f)

This column reports the aggregate grant date fair value of stock options. See Note 8 to the financial statements of Gulf Power in Item 8 herein for a discussion of the assumptions used in calculating these amounts.

Column (g)

The amounts in this column are the aggregate of the payouts under the annual Performance Pay Program and the Performance Dividend Program. The amount reported for the Performance Pay Program is for the one-year performance period that ended December 31, 2012. The amount reported for performance dividends is the amount earned at the end of the four-year performance-measurement period of January 1, 2009 through December 31, 2012. These awards were granted by the Compensation Committee in 2009 and are paid on stock options granted prior to 2010 that were outstanding at the end of 2012. As described in the CD&A, the Performance Dividend Program was eliminated by the Compensation Committee in 2010 and replaced with performance shares. This payout reported in column (g) is the third and final payout in the three-year transition period as described in the CD&A. The Performance Pay Program, the Performance Dividend Program, and performance shares are described in detail in the CD&A.

The amounts paid under each program to the named executive officers are shown below.

	Annual Performance-Based Compensation ($)	Performance Dividends ($)	Total ($)
S. W. Connally, Jr.	226,783	22,743	249,526
M. A. Crosswhite	397,755	70,568	468,323
R. S. Teel	115,118	28,217	143,335
M. L. Burroughs	91,572	3,062	94,634
P. B. Jacob	120,432	25,184	145,616
B. C. Terry	123,535	35,797	159,332

Column (h)

This column reports the aggregate change in the actuarial present value of each named executive officer's accumulated benefit under the Pension Plan and the supplemental pension plans (collectively, Pension Benefits) as of December 31, 2010, 2011, and 2012. The Pension Benefits as of each measurement date are based on the named executive officer's age, pay, and service accruals and the plan provisions applicable as of the measurement date. The actuarial present values as of each measurement date reflect the assumptions Gulf Power selected for cost purposes as of that measurement date; however, the named executive officers were assumed to remain employed at Gulf Power or any other Southern Company subsidiary until their benefits commence at the pension plans' stated normal retirement date, generally age 65. As a result, the amounts in column (h) related to Pension Benefits represent the combined impact of several factors: growth in the named executive officer's Pension Benefits over the measurement year; impact on the total present values of one year shorter discounting period due to the named executive officer being one year closer to normal retirement; impact on the total present values attributable to changes in assumptions from measurement date to measurement date; and impact on the total present values attributable to plan changes between measurement dates.

For more information about the Pension Benefits and the assumptions used to calculate the actuarial present value of accumulated benefits as of December 31, 2012, see the information following the Pension Benefits table. The key differences between assumptions used for the actuarial present values of accumulated benefits calculations as of December 31, 2011 and December 31, 2012 are:

- Discount rate for the Pension Plan was decreased to 4.30% as of December 31, 2012 from 5.0% as of December 31, 2011.

- Discount rate for the supplemental pension plans was decreased to 3.70% as of December 31, 2012 from 4.65% as of December 31, 2011.

This column also reports above-market earnings on deferred compensation under the Deferred Compensation Plan (DCP). However, there were no above-market earnings on deferred compensation in the years reported.

Column (i)

This column reports the following items: perquisites; tax reimbursements on certain perquisites; employer contributions in 2012 to the Southern Company Employee Savings Plan (ESP), which is a tax-qualified defined contribution plan intended to meet requirements of Section 401(k) of the Internal Revenue Code of 1986, as amended (Code); and contributions in 2012 under the Southern Company Supplemental Benefit Plan (Non-Pension Related) (SBP). The SBP is described more fully in the information following the Nonqualified Deferred Compensation table.

The amounts reported are itemized below.

	Perquisites ($)	Tax Reimbursements ($)	ESP ($)	SBP ($)	Total ($)
S. W. Connally, Jr.	148,057	16,200	12,108	2,943	179,308
M. A. Crosswhite	557,403	283,322	12,413	10,019	863,157
R. S. Teel	4,628	90	10,892	—	15,610
M. L. Burroughs	2,451	186	9,581	—	12,218
P. B. Jacob	5,149	368	10,952	202	16,671
B. C. Terry	5,392	288	10,943	287	16,910

Description of Perquisites

Personal Financial Planning is provided for most officers of Gulf Power, including all of the named executive officers. Gulf Power pays for the services of the financial planner on behalf of the officers, up to a maximum amount of $8,700 per year, after the initial year that the benefit is provided. In the initial year, the allowed amount is $15,000. Gulf Power also provides a five-year allowance of $6,000 for estate planning and tax return preparation fees.

Relocation Benefits. These benefits are provided to cover the costs associated with geographic relocation. Mr. Connally relocated from Atlanta, Georgia to Pensacola, Florida in 2012. Mr. Crosswhite relocated from Pensacola, Florida to Birmingham, Alabama in 2012. During 2012, Messrs. Connally and Crosswhite received relocation-related benefits in the amounts of $134,551 and $547,666, respectively. Relocation assistance includes the incremental cost paid or incurred for relocation, including loss on home sale and certain capital improvements of the residence in the former location, if applicable, home sale and home repurchase assistance (closing costs), shipment of household goods, temporary housing costs during the move, and in some cases, a lump sum relocation allowance, in lieu of the payment of certain relocation benefits. Under the relocation policy applicable to all employees, any loss on home sale is determined based on the purchase price paid for the residence plus the cost of capital improvements made within the last five years to the residence that qualify for addition to the tax basis of the residence. Also, as provided in the policy, tax assistance is provided on the taxable relocation benefits, including the reimbursement for loss on home sale. For Mr. Crosswhite, if he terminates within two years of his relocation, the amount provided for loss on home sale, including tax assistance, must be repaid. If Mr. Connally terminates within two years of his relocation, the amount provided for loss on home sale, including tax assistance, must be repaid.

Personal Use of Corporate-Owned Aircraft. Southern Company owns aircraft that are used to facilitate business travel. If seating is available, Southern Company permits a spouse or other family member to accompany an employee on a flight. However, because in such cases the aircraft is being used for a business purpose, there is no incremental cost associated with the family travel and no amounts are included for such travel. Any additional expenses incurred that are related to family travel are included. In connection with Mr. Connally's relocation, the Compensation Committee approved personal use of corporate-owned aircraft for a weekly round-trip between Atlanta and Pensacola for the first six months following his relocation to Pensacola. In connection with Mr. Crosswhite's relocation, the Compensation Committee approved personal use of corporate-owned aircraft for a weekly round-trip between Birmingham and Pensacola for the first six months following his relocation to Birmingham.

Other Miscellaneous Perquisites. The amount included reflects the full cost to Gulf Power of providing the following items: personal use of company-provided tickets for sporting and other entertainment events and gifts distributed to and activities provided to attendees at company-sponsored events.

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GRANTS OF PLAN-BASED AWARDS IN 2012

This table provides information on stock option grants made and goals established for future payouts under the performance-based compensation programs during 2012 by the Compensation Committee.

		Estimated Possible Payouts Under Non-Equity Incentive Plan Awards			Estimated Future Payouts Under Equity Incentive Plan Awards					
Name (a)	Grant Date (b)	Threshold ($) (c)	Target ($) (d)	Maximum ($) (e)	Threshold (#) (f)	Target (#) (g)	Maximum (#) (h)	All Other Option Awards: Number of Securities Underlying Options (#) (i)	Exercise or Base Price of Option Awards ($/Sh) (j)	Grant Date Fair Value of Stock and Option Awards ($) (k)
S. W. Connally, Jr.	2/13/2012	1,899	189,927	379,854						
	2/13/2012				19	1,944	3,888			81,629
	2/13/2012							16,053	44.42	54,420
M. A. Crosswhite	2/13/2012	3,179	317,932	635,864						
	2/13/2012				76	7,644	15,288			320,972
	2/13/2012							63,125	44.42	213,994
R. S. Teel	2/13/2012	1,076	107,587	215,174						
	2/13/2012				20	2,049	4,098			86,038
	2/13/2012							16,926	44.42	57,379
M. L. Burroughs	2/13/2012	757	75,680	151,360						
	2/13/2012				11	1,081	2,162			45,391
	2/13/2012							8,929	44.42	30,269
P. B. Jacob	2/13/2012	1,147	114,697	229,394						
	2/13/2012				22	2,185	4,370			91,748
	2/13/2012							18,044	44.42	61,169
B. C. Terry	2/13/2012	1,155	115,453	230,906						
	2/13/2012				22	2,199	4,398			92,336
	2/13/2012							18,163	44.42	61,573

Columns (c), (d), and (e)

These columns reflect the annual Performance Pay Program opportunity granted to the named executive officers in 2012 as described in the CD&A. The information shown as "Threshold," "Target," and "Maximum" reflects the range of potential payouts established by the Compensation Committee. The actual amounts earned are disclosed in the Summary Compensation Table.

Columns (f), (g), and (h)

These columns reflect the performance shares granted to the named executive officers in 2012 as described in the CD&A. The information shown as "Threshold," "Target," and "Maximum" reflects the range of potential payouts established by the Compensation Committee. Earned performance shares will be paid out in Common Stock following the end of the 2012-2014 performance period, based on the extent to which the performance goals are achieved. Any shares not earned are forfeited.

Columns (i) and (j)

Column (i) reflects the number of stock options granted to the named executive officers in 2012, as described in the CD&A, and column (j) reflects the exercise price of the stock options, which was the closing price on the grant date.

Column (k)

This column reflects the aggregate grant date fair value of the performance shares and stock options granted in 2012. For performance shares, the value is based on the probable outcome of the performance conditions as of the grant date using a Monte Carlo simulation model. For stock options, the value is derived using the Black-Scholes stock option pricing model.

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The assumptions used in calculating these amounts are discussed in Note 8 to the financial statements of Gulf Power in Item 8 herein.

OUTSTANDING EQUITY AWARDS AT 2012 FISCAL YEAR-END

This table provides information pertaining to all outstanding stock options and stock awards (performance shares) held by or granted to the named executive officers as of December 31, 2012.

	Option Awards				Stock Awards	
Name (a)	Number of Securities Underlying Unexercised Options Exercisable (#) (b)	Number of Securities Underlying Unexercised Options Unexercisable (#) (c)	Option Exercise Price ($) (d)	Option Expiration Date (e)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#) (f)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($) (g)
	5,096		33.81	02/20/2016		
	5,437		36.42	02/19/2017		
	8,521		35.78	02/18/2018		
S. W. Connally, Jr.	14,392		31.39	02/16/2019	4,364	186,823
	6,841	4,421	31.17	02/15/2020	3,888	166,455
	5,367	10,733	37.97	02/14/2021		
	0	16,053	44.42	02/13/2022		
	16,497		33.81	02/20/2016		
	22,578		36.42	02/19/2017		
	22,460		35.78	02/18/2018		
M. A. Crosswhite	42,242		31.39	02/16/2019	17,326	741,726
	12,851	12,851	31.17	02/15/2020	15,288	654,479
	21,309	42,617	37.97	02/14/2021		
	0	63,125	44.42	02/13/2022		
	2,050		32.70	02/18/2015		
	5,771		33.81	02/20/2016		
	9,265		36.42	02/19/2017		
R. S. Teel	9,078		35.78	02/18/2018	4,546	194,614
	15,332		31.39	02/16/2019	4,098	175,435
	4,919	4,710	31.17	02/15/2020		
	5,592	11,182	37.97	02/14/2021		
	0	16,926	44.42	02/13/2022		
	289		33.81	02/20/2016		
	1,604		36.42	02/19/2017		
M. L. Burroughs	2,610		35.78	02/18/2018	2,426	103,857
	0	1,207	31.17	02/15/2020	2,162	92,555
	2,986	5,970	37.97	02/14/2021		
	0	8,929	44.42	02/13/2022		

	13,925		36.42	02/19/2017		
	13,785		35.78	02/18/2018		
P. B. Jacob	9,326		31.39	02/16/2019	5,000	214,050
	7,254	8,553	31.17	02/15/2020	4,370	187,080
	0	12,301	37.97	02/14/2021		
	0	18,044	44.42	02/13/2022		
	8,905		33.81	02/20/2016		
	9,367		36.42	02/19/2017		
	12,918		35.78	02/18/2018	5,034	215,506
B. C. Terry	21,453		31.39	02/16/2019	4,398	188,278
	0	8,482	31.17	02/15/2020		
	6,192	12,382	37.97	02/14/2021		
	0	18,163	44.42	02/13/2022		

Columns (b), (c), (d), and (e)

Stock options vest one-third per year on the anniversary of the grant date. Options granted from 2005 through 2009 with expiration dates from 2015 through 2019 were fully vested as of December 31, 2012. The options granted in 2010, 2011, and 2012 become fully vested as shown below.

Year Option Granted	Expiration Date	Date Fully Vested
2010	February 15, 2020	February 15, 2013
2011	February 14, 2021	February 14, 2014
2012	February 13, 2022	February 13, 2015

Options also fully vest upon death, total disability, or retirement and expire three years following death or total disability or five years following retirement, or on the original expiration date if earlier. See Potential Payments upon Termination or Change in Control for more information about the treatment of stock options under different termination and change-in-control events.

Columns (f) and (g)

In accordance with SEC rules, column (f) reflects the maximum number of performance shares that can be earned at the end of each three-year performance period (December 31, 2013 and 2014) that were granted in 2011 and 2012, respectively. The performance shares granted for the 2010-2012 performance period vested December 31, 2012 and are shown in the Option Exercises and Stock Vested in 2012 table below. The value in column (g) is derived by multiplying the number of shares in column (f) by the Common Stock closing price on December 31, 2012 ($42.81). The ultimate number of shares earned, if any, will be based on the actual performance results at the end of each respective performance period. See further discussion of performance shares in the CD&A.

OPTION EXERCISES AND STOCK VESTED IN 2012

	Option Awards		Stock Awards	
Name	Number of Shares Acquired on Exercise (#)	Value Realized on Exercise ($)	Number of Shares Acquired on Vesting (#)	Value Realized on Vesting ($)
(a)	(b)	(c)	(d)	(e)
S. W. Connally, Jr.	7,353	104,842	1,987	85,063
M. A. Crosswhite	17,660	227,531	5,778	247,356
R. S. Teel	8,000	117,695	2,117	90,629
M. L. Burroughs	6,587	97,275	541	23,160
P. B. Jacob	13,151	167,074	3,845	164,604
B. C. Terry	14,772	220,759	3,812	163,192

Columns (b) and (c)

Column (b) reflects the number of shares acquired upon the exercise of stock options during 2012 and column (c) reflects the value realized. The value realized is the difference in the market price over the exercise price on the exercise date.

Columns (d) and (e)

Column (d) includes the performance shares awarded for the 2010-2012 performance period that vested on December 31, 2012. The value reflected in column (e) is derived by multiplying the number of shares in column (d) by the market value of the underlying shares on the vesting date ($42.81).

PENSION BENEFITS AT 2012 FISCAL YEAR-END

Name	Plan Name	Number of Years Credited Service (#)	Present Value of Accumulated Benefit ($)	Payments During Last Fiscal Year ($)
(a)	(b)	(c)	(d)	(e)
S.W. Connally, Jr.	Pension Plan	21.17	407,146	0
	SBP-P	21.17	165,494	0
	SERP	21.17	276,495	0
M. A. Crosswhite	Pension Plan	7.92	220,898	0
	SBP-P	7.92	275,275	0
	SERP	7.92	212,207	0
	SRA	15.00	1,436,775	0
R. S. Teel	Pension Plan	12.33	237,732	0
	SBP-P	12.33	35,828	0
	SERP	12.33	83,964	0
M. L. Burroughs	Pension Plan	20.58	447,509	0
	SBP-P	20.58	43,234	0
	SERP	20.58	157,502	0
P. B. Jacob	Pension Plan	29.42	1,114,934	0
	SBP-P	29.42	258,837	0
	SERP	29.42	298,205	0
B. C. Terry	Pension Plan	10.50	223,707	0
	SBP-P	10.50	39,955	0
	SERP	10.50	73,005	0
	SRA	10.00	368,454	0

Pension Plan

The Pension Plan is a tax-qualified, funded plan. It is Southern Company's primary retirement plan. Generally, all full-time employees participate in this plan after one year of service. Normal retirement benefits become payable when participants attain age 65 and complete five years of participation. The plan benefit equals the greater of amounts computed using a "1.7% offset formula" and a "1.25% formula," as described below. Benefits are limited to a statutory maximum.

The 1.7% offset formula amount equals 1.7% of final average pay times years of participation less an offset related to Social Security benefits. The offset equals a service ratio times 50% of the anticipated Social Security benefits in excess of $4,200. The service ratio adjusts the offset for the portion of a full career that a participant has worked. The highest three rates of pay out of a participant's last 10 calendar years of service are averaged to derive final average pay. The pay considered for this formula is the base salary rate with no adjustments for voluntary deferrals after 2008. A statutory limit restricts the amount considered each year; the limit for 2012 was $250,000.

The 1.25% formula amount equals 1.25% of final average pay times years of participation. For this formula, the final average pay computation is the same as above, but annual performance-based compensation earned each year is added to the base rates of pay.

Early retirement benefits become payable once plan participants have, during employment, attained age 50 and completed 10 years of participation. Participants who retire early from active service receive benefits equal to the amounts computed using the same formulas employed at normal retirement. However, a 0.3% reduction applies for each month (3.6% for each year) prior to normal retirement that participants elect to have their benefit payments commence. For example, 64% of the formula benefits are payable starting at age 55. As of December 31, 2012, Ms. Terry and Messrs. Connally, Crosswhite, and Teel were not retirement-eligible.

The Pension Plan's benefit formulas produce amounts payable monthly over a participant's post-retirement lifetime. At retirement, plan participants can choose to receive their benefits in one of seven alternative forms of payment. All forms pay benefits monthly over the lifetime of the retiree or the joint lifetimes of the retiree and a spouse. A reduction applies if a retiring participant chooses a payment form other than a single life annuity. The reduction makes the value of the benefits paid in the form chosen comparable to what it would have been if benefits were paid as a single life annuity over the retiree's life.

Participants vest in the Pension Plan after completing five years of service. All the named executive officers are vested in their Pension Plan benefits. Participants who terminate employment after vesting can elect to have their pension benefits commence at age 50 if they participated in the Pension Plan for 10 years. If such an election is made, the early retirement reductions that apply are actuarially determined factors and are larger than 0.3% per month.

If a participant dies while actively employed and is either age 50 or vested in the Pension Plan as of date of death, benefits will be paid to a surviving spouse. A survivor's benefit equals 45% of the monthly benefit that the participant had earned before his or her death. Payments to a surviving spouse of a participant who could have retired will begin immediately. Payments to a survivor of a participant who was not retirement-eligible will begin when the deceased participant would have attained age 50.

After commencing, survivor benefits are payable monthly for the remainder of a survivor's life. Participants who are eligible for early retirement may opt to have an 80% survivor benefit paid if they die; however, there is a charge associated with this election.

If participants become totally disabled, periods that Social Security or employer-provided disability income benefits are paid will count as service for benefit calculation purposes. The crediting of this additional service ceases at the point a disabled participant elects to commence retirement payments. Outside of this extra service crediting, the normal plan provisions apply to disabled participants.

The Southern Company Supplemental Benefit Plan (Pension-Related) (SBP-P)

The SBP-P is an unfunded retirement plan that is not tax qualified. This plan provides high-paid employees any benefits that the Pension Plan cannot pay due to statutory pay/benefit limits. The SBP-P's vesting and early retirement provisions mirror those of the Pension Plan. Its disability provisions mirror those of the Pension Plan but cease upon a participant's separation from service.

The amounts paid by the SBP-P are based on the additional monthly benefit that the Pension Plan would pay if the statutory limits and pay deferrals were ignored. When an SBP-P participant separates from service, vested monthly benefits provided by the benefit formulas are converted into a single sum value. It equals the present value of what would have been paid monthly for an actuarially determined average post-retirement lifetime. The discount rate used in the calculation is based on the 30-year U.S. Treasury yields for the September preceding the calendar year of separation, but not more than six percent.

Vested participants terminating prior to becoming eligible to retire will be paid their single sum value as of September 1 following the calendar year of separation. If the terminating participant is retirement eligible, the single sum value will be paid in 10 annual installments starting shortly after separation. The unpaid balance of a retiree's single sum will be credited with interest at the prime rate published in The Wall Street Journal. If the separating participant is a "key man" under Section 409A of the Code, the first installment will be delayed for six months after the date of separation.

If an SBP-P participant dies after becoming vested in the Pension Plan, the spouse of the deceased participant will receive the installments the participant would have been paid upon retirement. If a vested participant's death occurs prior to age 50, the installments will be paid to a spouse as if the participant had survived to age 50.

The Southern Company Supplemental Executive Retirement Plan (SERP)

The SERP is also an unfunded retirement plan that is not tax qualified. This plan provides high-paid employees additional benefits that the Pension Plan and the SBP-P would pay if the 1.7% offset formula calculations reflected a portion of annual performance-based compensation. To derive the SERP benefits, a final average pay is determined reflecting participants' base rates of pay and their annual performance-based compensation amounts, whether or not deferred, to the extent they exceed 15% of those base rates (ignoring statutory limits). This final average pay is used in the 1.7% offset formula to derive a gross benefit. The Pension Plan and the SBP-P benefits are subtracted from the gross benefit to calculate the SERP benefit. The SERP's early retirement, survivor benefit, disability, and form of payment provisions mirror the SBP-P's provisions. However, except upon a change in control, SERP benefits do not vest until participants retire, so no benefits are paid if a participant terminates prior to becoming retirement-eligible. More information about vesting and payment of SERP benefits following a change in control is included in the section entitled "Potential Payments upon Termination or Change in Control."

Supplemental Pension Benefit Agreements (SRA)

Gulf Power also provides supplemental retirement benefits to certain employees that were first employed by Gulf Power, or an affiliate of Gulf Power, in the middle of their careers and generally provide for additional retirement benefits by giving credit for years of employment prior to employment with Gulf Power or one of its affiliates. Information about the supplemental retirement agreements with Ms. Terry and Mr. Crosswhite is included in the CD&A.

The following assumptions were used in the present value calculations for pension benefits:

- Discount rate - 4.30% Pension Plan and 3.70% supplemental plans as of December 31, 2012
- Retirement date - Normal retirement age (65 for all named executive officers)
- Mortality after normal retirement - RP2000 Combined Healthy with generational projections
- Mortality, withdrawal, disability, and retirement rates prior to normal retirement - None
- Form of payment for Pension Benefits:
  - Male retirees: 25% single life annuity; 25% level income annuity; 25% joint and 50% survivor annuity; and 25% joint and 100% survivor annuity
  - Female retirees: 40% single life annuity; 40% level income annuity; 10% joint and 50% survivor annuity; and 10% joint and 100% survivor annuity
- Spouse ages - Wives two years younger than their husbands
- Annual performance-based compensation earned but unpaid as of the measurement date - 130% of target opportunity percentages times base rate of pay for year amount is earned
- Installment determination - 3.75% discount rate for single sum calculation and 4.50% prime rate during installment payment period

For all of the named executive officers, the number of years of credited service for the Pension Plan, the SBP-P, and the SERP is one year less than the number of years of employment.

NONQUALIFIED DEFERRED COMPENSATION AS OF 2012 FISCAL YEAR-END

Name (a)	Executive Contributions in Last FY ($) (b)	Registrant Contributions in Last FY ($) (c)	Aggregate Earnings in Last FY ($) (d)	Aggregate Withdrawals/ Distributions ($) (e)	Aggregate Balance at Last FYE ($) (f)
S. W. Connally, Jr.	20,370	2,943	2,686	—	90,622
M. A. Crosswhite	—	10,019	3,634	—	197,784
R. S. Teel	—	—	(5)	—	129
M. L. Burroughs	—	—	—	—	—
P. B. Jacob	38,888	202	15,326	—	382,335
B. C. Terry	60,557	287	4,005	—	138,171

Southern Company provides the DCP which is designed to permit participants to defer income as well as certain federal, state, and local taxes until a specified date or their retirement, or other separation from service. Up to 50% of base salary and up to 100% of performance-based non-equity compensation may be deferred at the election of eligible employees. All of the named executive officers are eligible to participate in the DCP.

Participants have two options for the deemed investments of the amounts deferred - the Stock Equivalent Account and the Prime Equivalent Account. Under the terms of the DCP, participants are permitted to transfer between investments at any time.
The amounts deferred in the Stock Equivalent Account are treated as if invested at an equivalent rate of return to that of an actual investment in Common Stock, including the crediting of dividend equivalents as such are paid by Southern Company from time to time. It provides participants with an equivalent opportunity for the capital appreciation (or loss) and income of that of a Southern Company stockholder. During 2012, the rate of return in the

Stock Equivalent Account was -3.4% which was Southern Company's total shareholder return for 2012.

Alternatively, participants may elect to have their deferred compensation deemed invested in the Prime Equivalent Account which is treated as if invested at a prime interest rate compounded monthly, as published in The Wall Street Journal as the base rate on corporate loans posted as of the last business day of each month by at least 75% of the United States' largest banks. The interest rate earned on amounts deferred during 2012 in the Prime Equivalent Account was 3.25%.

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Column (b)

This column reports the actual amounts of compensation deferred under the DCP by each named executive officer in 2012. The amount of salary deferred by the named executive officers, if any, is included in the Salary column in the Summary Compensation Table. The amounts of performance-based compensation deferred in 2012 were the amounts paid for performance under the annual Performance Pay Program and the Performance Dividend Program that were earned as of December 31, 2011 but not payable until the first quarter of 2012. These amounts are not reflected in the Summary Compensation Table because that table reports performance-based compensation that was earned in 2012, but not payable until early 2013. These deferred amounts may be distributed in a lump sum or in up to 10 annual installments at termination of employment or in a lump sum at a specified date, at the election of the participant.

Column (c)

This column reflects contributions under the SBP. Under the Code, employer matching contributions are prohibited under the ESP on employee contributions above stated limits in the ESP, and, if applicable, above legal limits set forth in the Code. The SBP is a nonqualified deferred compensation plan under which contributions are made that are prohibited from being made in the ESP. The contributions are treated as if invested in Common Stock and are payable in cash upon termination of employment in a lump sum or in up to 20 annual installments, at the election of the participant. The amounts reported in this column also were reported in the All Other Compensation column in the Summary Compensation Table.

Column (d)

This column reports earnings or losses on both compensation the named executive officers elected to defer and on employer contributions under the SBP.

Column (f)

This column includes amounts that were deferred under the DCP and contributions under the SBP in prior years and reported in Gulf Power's prior years' Information Statements or Annual Reports on Form 10-K. The chart below shows the amounts reported in Gulf Power's prior years' Information Statements or Annual Reports on Form 10-K.

Name	Amounts Deferred under the DCP Prior to 2012 and Reported in Prior Years' Information Statements or Annual Reports on Form 10-K ($)	Employer Contributions under the SBP Prior to 2012 and Reported in Prior Years' Information Statements or Annual Reports on Form 10-K ($)	Total ($)
S. W. Connally, Jr.	—	—	—
M. A. Crosswhite	23,316	7,698	31,014
R. S. Teel	—	—	—
M. L. Burroughs	—	—	—
P. B. Jacob	218,217	22,888	241,105
B. C. Terry	121,427	265	121,692

POTENTIAL PAYMENTS UPON TERMINATION OR CHANGE IN CONTROL

This section describes and estimates payments that could be made to the named executive officers under different termination and change-in-control events. The estimated payments would be made under the terms of Southern Company's compensation and benefit program or the change-in-control severance program. All of the named executive officers are participants in Southern Company's change-in-control severance program for officers. The amount of potential payments is calculated as if the triggering events occurred as of December 31, 2012 and assumes that the price of Common Stock is the closing market price on December 31, 2012.

Description of Termination and Change-in-Control Events

The following charts list different types of termination and change-in-control events that can affect the treatment of payments under the compensation and benefit programs. No payments are made under the change-in-control severance program unless, within two years of the change in control, the named executive officer is involuntarily terminated or voluntarily terminates for Good Reason. (See the description of Good Reason below.)

Traditional Termination Events

- Retirement or Retirement-Eligible - Termination of a named executive officer who is at least 50 years old and has at least 10 years of credited service.
- Resignation - Voluntary termination of a named executive officer who is not retirement-eligible.
- Lay Off - Involuntary termination of a named executive officer who is not retirement-eligible not for cause.
- Involuntary Termination - Involuntary termination of a named executive officer for cause. Cause includes individual performance below minimum performance standards and misconduct, such as violation of Gulf Power's Drug and Alcohol Policy.
- Death or Disability - Termination of a named executive officer due to death or disability.

Change-in-Control-Related Events

At the Southern Company or Gulf Power level:

- Southern Company Change-in-Control I - Acquisition by another entity of 20% or more of Common Stock, or following a merger with another entity Southern Company's stockholders own 65% or less of the entity surviving the merger.
- Southern Company Change-in-Control II - Acquisition by another entity of 35% or more of Common Stock, or following a merger with another entity Southern Company shareholders own less than 50% of Southern Company surviving the merger.
- Southern Company Termination - A merger or other event and Southern Company is not the surviving company or the Common Stock is no longer publicly traded.
- Gulf Power Change in Control - Acquisition by another entity, other than another subsidiary of Southern Company, of 50% or more of the stock of Gulf Power, a merger with another entity and Gulf Power is not the surviving company, or the sale of substantially all the assets of Gulf Power.

At the employee level:

- Involuntary Change-in-Control Termination or Voluntary Change-in-Control Termination for Good Reason - Employment is terminated within two years of a change in control, other than for cause, or the employee voluntarily terminates for Good Reason. Good Reason for voluntary termination within two years of a change in control generally is satisfied when there is a material reduction in salary, performance-based compensation opportunity or benefits, relocation of over 50 miles, or a diminution in duties and responsibilities.

The following chart describes the treatment of different pay and benefit elements in connection with the Traditional Termination Events described above.

Program	Retirement/ Retirement-Eligible	Lay Off (Involuntary Termination Not For Cause)	Resignation	Death or Disability	Involuntary Termination (For Cause)
Pension Benefits Plans	Benefits payable as described in the notes following the Pension Benefits table.	Same as Retirement.	Same as Retirement.	Same as Retirement.	Same as Retirement.
Annual Performance Pay Program	Prorated if retire before 12/31.	Same as Retirement.	Forfeit.	Same as Retirement.	Forfeit.
Performance Dividend Program	Paid year of retirement plus two additional years.	Forfeit.	Forfeit.	Payable until options expire or exercised.	Forfeit.
Stock Options	Vest; expire earlier of original expiration date or five years.	Vested options expire in 90 days; unvested are forfeited.	Same as Lay Off.	Vest; expire earlier of original expiration date or three years.	Forfeit.
Performance Shares	Prorated if retire prior to end of performance period.	Forfeit.	Forfeit.	Same as Retirement.	Forfeit.
Financial Planning Perquisite	Continues for one year.	Terminates.	Terminates.	Same as Retirement.	Terminates.
Deferred Compensation Plan	Payable per prior elections (lump sum or up to 10 annual installments).	Same as Retirement.	Same as Retirement.	Payable to beneficiary or participant per prior elections. Amounts deferred prior to 2005 can be paid as a lump sum per benefit administration committee's discretion.	Same as Retirement.
Supplemental Benefit Plan - non-pension related	Payable per prior elections (lump sum or up to 20 annual installments).	Same as Retirement.	Same as Retirement.	Same as the Deferred Compensation Plan.	Same as Retirement.

The chart below describes the treatment of payments under compensation and benefit programs under different change-in-control events, except the Pension Plan. The Pension Plan is not affected by change-in-control events.

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Program	Southern Company Change-in-Control I	Southern Company Change-in-Control II	Southern Company Termination or Gulf Power Change in Control	Involuntary Change-in-Control-Related Termination or Voluntary Change-in-Control-Related Termination for Good Reason
Nonqualified Pension Benefits	All SERP-related benefits vest if participants vested in tax-qualified pension benefits; otherwise, no impact. SBP - pension-related benefits vest for all participants and single sum value of benefits earned to change-in-control date paid following termination or retirement.	Benefits vest for all participants and single sum value of benefits earned to the change-in-control date paid following termination or retirement.	Same as Southern Company Change-in-Control II.	Based on type of change-in-control event.
Annual Performance Pay Program	If no program termination, paid at greater of target or actual performance. If program terminated within two years of change in control, prorated at target performance level.	Same as Southern Company Change-in-Control I.	Prorated at target performance level.	If not otherwise eligible for payment, if the program is still in effect, prorated at target performance level.
Performance Dividend Program	If no program termination, paid at greater of target or actual performance. If program terminated within two years of change in control, prorated at greater of target or actual performance level.	Same as Southern Company Change-in-Control I.	Prorated at greater of actual or target performance level.	If not otherwise eligible for payment, if the program is still in effect, greater of actual or target performance level for year of severance only.
Stock Options	Not affected by change-in-control events.	Not affected by change-in-control events.	Vest and convert to surviving company's securities; if cannot convert, pay spread in cash.	Vest.

Performance Shares	Not affected by change-in-control events.	Not affected by change-in-control events.	Vest and convert to surviving company's securities; if cannot convert, pay spread in cash.	Vest.
DCP	Not affected by change-in-control events.	Not affected by change-in-control events.	Not affected by change-in-control events.	Not affected by change-in-control events.

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Program	Southern Company Change-in-Control I	Southern Company Change-in-Control II	Southern Company Termination or Gulf Power Change in Control	Involuntary Change-in-Control-Related Termination or Voluntary Change-in-Control-Related Termination for Good Reason
SBP	Not affected by change-in-control events.	Not affected by change-in-control events.	Not affected by change-in-control events.	Not affected by change-in-control events.
Severance Benefits	Not applicable.	Not applicable.	Not applicable.	One or two times base salary plus target annual performance-based pay.
Healthcare Benefits	Not applicable.	Not applicable.	Not applicable.	Up to five years participation in group healthcare plan plus payment of two or three years' premium amounts.
Outplacement Services	Not applicable.	Not applicable.	Not applicable.	Six months.

Potential Payments

This section describes and estimates payments that would become payable to the named executive officers upon a termination or change in control as of December 31, 2012.

Pension Benefits

The amounts that would have become payable to the named executive officers if the Traditional Termination Events occurred as of December 31, 2012 under the Pension Plan, the SBP-P, the SERP, and, if applicable, an SRA are itemized in the chart below. The amounts shown under the column Retirement are amounts that would have become payable to the named executive officers that were retirement-eligible on December 31, 2012 and are the monthly Pension Plan benefits and the first of 10 annual installments from the SBP-P and the SERP. The amounts shown under the column Resignation or Involuntary Termination are the amounts that would have become payable to the named executive officers who were not retirement-eligible on December 31, 2012 and are the monthly Pension Plan benefits that would become payable as of the earliest possible date under the Pension Plan and the single sum value of benefits earned up to the termination date under the SBP-P, paid as a single payment rather than in 10 annual installments. Benefits under the SERP would be forfeited. The amounts shown that are payable to a spouse in the event of the death of the named executive officer are the monthly amounts payable to a spouse under the Pension Plan and the first of 10 annual installments from the SBP-P and the SERP. The amounts in this chart are very different from the pension values shown in the Summary Compensation Table and the Pension Benefits table. Those tables show the present values of all the benefits amounts anticipated to be paid over the lifetimes of the named executive officers and their spouses. Those plans are described in the notes following the Pension Benefits table. Of the named executive officers, Ms. Terry and Messrs. Connally, Crosswhite, and Teel were not retirement-eligible on December 31, 2012. The SRA for Ms. Terry contains an additional service requirement for benefit eligibility which was not met as of December 31, 2012. Therefore she was not eligible to receive retirement benefits under the agreement. However, death benefits would be paid to her surviving spouse.

Name	Retirement ($)		Resignation or Involuntary Termination ($)	Death (payments to a spouse) ($)
S. W. Connally, Jr.	Pension	n/a	1,766	2,900
	SBP-P	n/a	192,119	24,102
	SERP	n/a	—	40,268
M. A. Crosswhite	Pension	n/a	2,653	1,194
	SBP-P	n/a	308,771	31,227
	SERP	n/a	—	24,111
	SRA	n/a	1,146,097	163,246
R. S. Teel	Pension	n/a	1,047	1,720
	SBP-P	n/a	41,679	5,297
	SERP	n/a	—	12,415
M. L. Burroughs	Pension	2,655	All plans treated as retiring	2,221
	SBP-P	5,138		5,138
	SERP	18,717		18,717
P. B. Jacob	Pension	7,304	All plans treated as retiring	4,291
	SBP-P	30,467		30,467
	SERP	35,101		35,101
B. C. Terry	Pension	n/a	967	1,588
	SBP-P	n/a	46,355	5,926
	SERP	n/a	—	10,827
	SRA	n/a	—	54,644

As described in the Change-in-Control chart, the only change in the form of payment, acceleration, or enhancement of the pension benefits is that the single sum value of benefits earned up to the change-in-control date under the SBP-P and the SERP could be paid as a single payment rather than in 10 annual installments. Also, the SERP benefits vest for participants who are not retirement-eligible upon a change in control. Estimates of the single sum payment that would have been made to the named executive officers, assuming termination as of December 31, 2012 following a change-in-control event, other than a Southern Company Change-in-Control I (which does not impact how pension benefits are paid), are itemized below. These amounts would be paid instead of the benefits shown in the Traditional Termination Events chart above; they are not paid in addition to those amounts.

Name	SBP-P ($)	SERP ($)	SRA ($)	Total ($)
S. W. Connally, Jr.	188,642	315,169	—	503,811
M. A. Crosswhite	303,183	233,722	1,582,443	2,119,348
R. S. Teel	40,925	95,910	—	136,835
M. L. Burroughs	51,378	187,169	—	238,547
P. B. Jacob	304,668	351,007	—	655,675
B. C. Terry	45,516	83,165	419,734	548,415

The pension benefit amounts in the tables above were calculated as of December 31, 2012 assuming payments would begin as soon as possible under the terms of the plans. Accordingly, appropriate early retirement reductions were applied. Any unpaid annual performance-based compensation was assumed to be paid at 1.30 times the target level. Pension Plan benefits were

calculated assuming each named executive officer chose a single life annuity form of payment, because that results in the greatest monthly benefit. The single sum values were based on a 3.18% discount rate.

Annual Performance Pay Program

The amount payable if a change in control had occurred on December 31, 2012 is the greater of target or actual performance. Because actual payouts for 2012 performance were above the target level, the amount that would have been payable was the actual amount paid as reported in the Summary Compensation Table.

Performance Dividends

Because the assumed termination date is December 31, 2012, there is no additional amount that would be payable other than what was reported in the Summary Compensation Table. As described in the Traditional Termination Events chart, there is some continuation of benefits under the Performance Dividend Program for retirees. Under Change-in-Control-Related Events, performance dividends are payable at the greater of target performance or actual performance. For the 2009-2012 performance-measurement period, actual performance was less than target-level performance. The chart below shows the additional amounts that would have been paid upon a change in control.

Name	Additional Performance Dividends ($)
S. W. Connally, Jr.	9,741
M. A. Crosswhite	30,225
R. S. Teel	12,086
M. L. Burroughs	1,312
P. B. Jacob	10,787
B. C. Terry	15,332

Stock Options and Performance Share Units (Equity Awards)

Equity Awards would be treated as described in the Termination and Change-in-Control charts above. Under a Southern Company Termination, all Equity Awards vest. In addition, if there is an Involuntary Change-in-Control Termination or Voluntary Change-in-Control Termination for Good Reason, Equity Awards vest. There is no payment associated with Equity Awards unless there is a Southern Company Termination and the participants' Equity Awards cannot be converted into surviving company awards. In that event, the value of outstanding Equity Awards would be paid to the named executive officers. For stock options, that value is the excess of the exercise price and the closing price of Common Stock on December 31, 2012 and, for performance shares, it is the closing price on December 31, 2012. The chart below shows the number of stock options for which vesting would be accelerated under a Southern Company Termination and the amount that would be payable under a Southern Company Termination if there were no conversion to the surviving company's stock options. It also shows the number and value of performance shares that would be paid.

	Number of Equity Awards with Accelerated Vesting (#)		Total Number of Equity Awards Following Accelerated Vesting (#)		Total Payable in Cash without Conversion of Equity Awards ($)
Name	Stock Options	Performance Shares	Stock Options	Performance Shares	
S. W. Connally, Jr.	31,207	4,126	76,861	4,126	690,513

M. A. Crosswhite	118,593	16,307	256,530	16,307	2,239,720
R. S. Teel	32,818	4,322	84,825	4,322	749,070
M. L. Burroughs	16,106	2,294	23,595	2,294	186,802
P. B. Jacob	38,898	4,685	83,188	4,685	736,487
B. C. Terry	32,818	4,716	97,862	4,716	866,328

DCP and SBP
The aggregate balances reported in the Nonqualified Deferred Compensation table would be payable to the named executive officers as described in the Traditional Termination and Change-in-Control-Related Events charts above. There is no enhancement or acceleration of payments under these plans associated with termination or change-in-control events, other than the lump-sum payment opportunity described in the above charts. The lump sums that would be payable are those that are reported in the Nonqualified Deferred Compensation table.

Healthcare Benefits
Messrs. Burroughs and Jacob are retirement-eligible. Healthcare benefits are provided to retirees and there is no incremental payment associated with the termination or change-in-control events. At the end of 2012, the other named executive officers were not retirement-eligible and thus healthcare benefits would not become available until each reaches age 50, except in the case of a change-in-control-related termination, as described in the Change-in-Control-Related Events chart. The estimated cost of providing healthcare insurance premiums is less than $20,000 per year for up to a maximum of two years for Ms. Terry and Mr. Teel and up to a maximum of three years for Messrs. Connally and Crosswhite.

Financial Planning Perquisite
Since Messrs. Burroughs and Jacob are retirement-eligible, an additional year of the Financial Planning perquisite, which is set at a maximum of $8,700 per year, will be provided after retirement. The other named executive officers are not retirement-eligible.

There are no other perquisites provided to the named executive officers under any of the traditional termination or change-in-control-related events.

Severance Benefits
The named executive officers are participants in a change-in-control severance plan. The plan provides severance benefits, including outplacement services, if within two years of a change in control, they are involuntarily terminated, not for Cause, or they voluntarily terminate for Good Reason. The severance benefits are not paid unless the named executive officer releases the employing company from any claims he or she may have against the employing company.

The estimated cost of providing the six months of outplacement services is $6,000 per named executive officer. The severance payment is two times the base salary and target payout under the annual Performance Pay Program for Messrs. Connally and Crosswhite and one times the base salary and target payout under the annual Performance Pay Program for the other named executive officers.

The table below estimates the severance payments that would be made to the named executive officers if they were terminated as of December 31, 2012 in connection with a change in control.

Name	Severance Amount ($)
S. W. Connally, Jr.	1,156,000
M. A. Crosswhite	1,661,750
R. S. Teel	346,669
M. L. Burroughs	264,879
P. B. Jacob	369,579

B. C. Terry	372,016

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DIRECTOR COMPENSATION

Only non-employee directors of Gulf Power are compensated for service on the board of directors.

During 2012, the pay components for non-employee directors were:

Annual cash retainer:	$22,000 per year
Annual stock retainer:	$19,500 per year in Common Stock
Board meeting fees:	If more than five meetings are held in a calendar year, $1,200 will be paid for participation beginning with the sixth meeting.
Committee meeting fees:	If more than five meetings of any one committee are held in a calendar year, $1,000 will be paid for participation in each meeting of that committee beginning with the sixth meeting.

DIRECTOR DEFERRED COMPENSATION PLAN

Any deferred quarterly equity grants or stock retainers are required to be deferred in the Deferred Compensation Plan For Directors of Gulf Power Company (Director Deferred Compensation Plan) and are invested in Common Stock units which earn dividends as if invested in Common Stock. Earnings are reinvested in additional stock units. Upon leaving the board, distributions are made in shares of Common Stock.

In addition, directors may elect to defer up to 100% of their remaining compensation in the Director Deferred Compensation Plan until membership on the board ends. Deferred compensation may be invested as follows, at the director's election:

- in Common Stock units which earn dividends as if invested in Common Stock and are distributed in shares of Common Stock upon leaving the board;
- in Common Stock units which earn dividends as if invested in Common Stock and are distributed in cash upon leaving the board; or
- at prime interest which is paid in cash upon leaving the board.

All investments and earnings in the Director Deferred Compensation Plan are fully vested and, at the election of the director, may be distributed in a lump sum payment or in up to 10 annual distributions after leaving the board.

DIRECTOR COMPENSATION TABLE

The following table reports all compensation to Gulf Power's non-employee directors during 2012, including amounts deferred in the Director Deferred Compensation Plan. Non-employee directors do not receive Non-Equity Incentive Plan Compensation, and there is no pension plan for non-employee directors.

Name	Fees Earned or Paid in Cash ($)(1)	Stock Awards ($)(2)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)(3)	All Other Compensation ($)	Total ($)
Allan G. Bense	23,200	19,500	0	49	42,749
Deborah H. Calder	23,200	19,500	0	49	42,749
William C. Cramer, Jr.	23,200	19,500	0	498	43,198
J. Mort O'Sullivan III	23,200	19,500	0	498	43,198
William A. Pullum (4)	11,000	9,750	0	1,112	21,862
Winston E. Scott	23,200	19,500	0	49	42,749

(1) Includes amounts voluntarily deferred in the Director Deferred Compensation Plan.

(2) Includes fair market value of equity grants on grant dates. All such stock awards are vested immediately upon grant.

(3) Above-market earnings on amounts invested in the Director Deferred Compensation Plan. Above-market earnings are defined by the SEC as any amount above 120% of the applicable federal long-term rate as prescribed under Section 1274(d) of the Code.

(4) Mr. Pullum retired from Gulf Power's board of directors effective May 14, 2012.

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COMPENSATION COMMITTEE INTERLOCKS AND INSIDER PARTICIPATION

The Compensation Committee is made up of non-employee directors of Southern Company who have never served as executive officers of Southern Company or Gulf Power. During 2012, none of Southern Company's or Gulf Power's executive officers served on the board of directors of any entities whose directors or officers serve on the Compensation Committee.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

(a) Security Ownership (Applicable to Gulf Power only).

Security Ownership of Certain Beneficial Owners. Southern Company is the beneficial owner of 100% of the outstanding common stock of Gulf Power.

Title of Class	Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class	
Common Stock	The Southern Company 30 Ivan Allen Jr. Boulevard, N.W. Atlanta, Georgia 30308		100	%
	Registrant: Gulf Power	4,542,717		

Security Ownership of Management. The following tables show the number of shares of Common Stock owned by the directors, nominees, and executive officers as of December 31, 2012. It is based on information furnished by the directors, nominees, and executive officers. The shares owned by all directors, nominees, and executive officers as a group constitute less than one percent of the total number of shares outstanding on December 31, 2012.

		Shares Beneficially Owned Include:	
Name of Directors, Nominees, and Executive Officers	Shares Beneficially Owned (1)	Deferred Stock Units (2)	Shares Individuals Have Rights to Acquire Within 60 Days (3)
S. W. Connally, Jr.	67,040	0	62,129
Allan G. Bense	1,427	0	0
Deborah H. Calder	1,422	963	0
William C. Cramer, Jr.	14,033	14,033	0
J. Mort O'Sullivan III	2,024	2,024	0
Winston E. Scott	6,154	0	0
P. Bernard Jacob	75,247	0	67,686
Michael L. Burroughs	18,468	0	15,022
Richard S. Teel	69,959	0	69,375
Bentina C. Terry	86,562	0	82,216
Directors, Nominees, and Executive Officers as a group (10 people)	342,336	17,020	296,428

(1)

"Beneficial ownership" means the sole or shared power to vote, or to direct the voting of, a security and/or investment power with respect to a security or any combination thereof.

(2) Indicates the number of deferred stock units held under the Director Deferred Compensation Plan.

(3) Indicates shares of Common Stock that certain executive officers have the right to acquire within 60 days. Shares indicated are included in the Shares Beneficially Owned column.

Changes in Control. Southern Company and Gulf Power know of no arrangements which may at a subsequent date result in any change-in-control.

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(b) Equity Compensation Plan Information (Applicable to all registrants).

The following table provides information as of December 31, 2012 concerning shares of Common Stock authorized for issuance under Southern Company's existing non-qualified equity compensation plans.

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants, and rights (a)	Weighted-average exercise price of outstanding options, warrants, and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	35,916,303	$36.37	39,813,434 (1)
Equity compensation plans not approved by security holders	n/a	n/a	n/a

(1) Includes shares available for future issuance under the Omnibus Incentive Compensation Plan (38,603,602) and the Outside Directors Stock Plan (1,209,832).

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE.

Transactions with Related Persons. None.

Review, Approval or Ratification of Transactions with Related Persons.

Gulf Power does not have a written policy pertaining solely to the approval or ratification of "related party transactions." Southern Company has a Code of Ethics as well as a Contract Guidance Manual and other formal written procurement policies and procedures that guide the purchase of goods and services, including requiring competitive bids for most transactions above $10,000 or approval based on documented business needs for sole sourcing arrangements. The approval and ratification of any related party transactions would be subject to these written policies and procedures which include a determination of the need for the goods and services; preparation and evaluation of requests for proposals by supply chain management; the writing of contracts; controls and guidance regarding the evaluation of the proposals; and negotiation of contract terms and conditions. As appropriate, these contracts are also reviewed by individuals in the legal, accounting, and/or risk management/ services departments prior to being approved by the responsible individual. The responsible individual will vary depending on the department requiring the goods and services, the dollar amount of the contract, and the appropriate individual within that department who has the authority to approve a contract of the applicable dollar amount.

Director Independence.

The board of directors of Gulf Power consists of five non-employee directors (Ms. Deborah H. Calder and Messrs. Allan G. Bense, William C. Cramer, Jr., J. Mort O'Sullivan, III, and Winston E. Scott) and Mr. Connally. Mr. William A. Pullum retired from the board of directors effective May 14, 2012.

Southern Company owns all of Gulf Power's outstanding common stock. Gulf Power has listed only debt securities on the NYSE. Accordingly, under the rules of the NYSE, Gulf Power is exempt from most of the NYSE's listing standards relating to corporate governance, including requirements relating to certain board committees. Gulf Power has voluntarily complied with certain NYSE listing standards relating to corporate governance where such compliance was deemed to be in the best interests of Gulf Power's shareholders.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The following represents the fees billed to Gulf Power and Southern Power for the last two fiscal years by Deloitte & Touche LLP, each company's principal public accountant for 2012 and 2011:

	2012	2011
	(in thousands)	
Gulf Power		
Audit Fees (1)	$1,454	$1,326
Audit-Related Fees (2)	—	118
Tax Fees	—	—
All Other Fees	—	—
Total	$1,454	$1,444
Southern Power		
Audit Fees (1)	$1,279	$1,270
Audit-Related Fees	—	—
Tax Fees	—	—
All Other Fees	—	—
Total	$1,279	$1,270

(1) Includes services performed in connection with financing transactions.
(2) Includes other non-statutory audit services and accounting consultations.

The Southern Company Audit Committee (on behalf of Southern Company and its subsidiaries) adopted a Policy of Engagement of the Independent Auditor for Audit and Non-Audit Services that includes requirements for such Audit Committee to pre-approve audit and non-audit services provided by Deloitte & Touche LLP. All of the audit services provided by Deloitte & Touche LLP in fiscal years 2012 and 2011 (described in the footnotes to the table above) and related fees were approved in advance by the Southern Company Audit Committee.

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PART IV

Item 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed as a part of this report on Form 10-K:

(1) Financial Statements and Financial Statement Schedules:

Management's Report on Internal Control Over Financial Reporting for Southern Company and Subsidiary Companies is listed under Item 8 herein.

Management's Report on Internal Control Over Financial Reporting for Alabama Power is listed under Item 8 herein.

Management's Report on Internal Control Over Financial Reporting for Georgia Power is listed under Item 8 herein.

Management's Report on Internal Control Over Financial Reporting for Gulf Power is listed under Item 8 herein.

Management's Report on Internal Control Over Financial Reporting for Mississippi Power is listed under Item 8 herein.

Management's Report on Internal Control Over Financial Reporting for Southern Power and Subsidiary Companies is listed under Item 8 herein.

Reports of Independent Registered Public Accounting Firm on the financial statements and financial statement schedules for Southern Company and Subsidiary Companies, Alabama Power, Georgia Power, Gulf Power and Mississippi Power, as well as the Report of Independent Registered Public Accounting Firm on the financial statements of Southern Power and Subsidiary Companies are listed under Item 8 herein.

The financial statements filed as a part of this report for Southern Company and Subsidiary Companies, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power and Subsidiary Companies are listed under Item 8 herein.

The financial statement schedules for Southern Company and Subsidiary Companies, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power are listed in the Index to the Financial Statement Schedules at page S-1.

(2) Exhibits:

Exhibits for Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power are listed in the Exhibit Index at page E-1.

THE SOUTHERN COMPANY
SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

THE SOUTHERN COMPANY

By:	Thomas A. Fanning Chairman, President, and Chief Executive Officer
By:	/s/Melissa K. Caen (Melissa K. Caen, Attorney-in-fact)
Date:	February 27, 2013

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Thomas A. Fanning
Chairman, President,
Chief Executive Officer, and Director
(Principal Executive Officer)

Art P. Beattie
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

W. Ron Hinson
Comptroller and Chief Accounting Officer
(Principal Accounting Officer)

Directors:

Juanita Powell Baranco	Warren A. Hood, Jr.
Jon A. Boscia	Donald M. James
Henry A. Clark III	Dale E. Klein
David J. Grain	William G. Smith, Jr.
H. William Habermeyer, Jr.	Steven R. Specker
Veronica M. Hagen	E. Jenner Wood III

By: /s/Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)
Date: February 27, 2013

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ALABAMA POWER COMPANY
SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

ALABAMA POWER COMPANY

By: Charles D. McCrary
President and Chief Executive Officer

By: /s/Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)

Date: February 27, 2013

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Charles D. McCrary
President, Chief Executive Officer, and Director
(Principal Executive Officer)

Philip C. Raymond
Executive Vice President, Chief Financial Officer, and Treasurer
(Principal Financial Officer)

Anita Allcorn-Walker
Vice President and Comptroller
(Principal Accounting Officer)

Directors:

Whit Armstrong	James K. Lowder
Ralph D. Cook	Malcolm Portera
David J. Cooper, Sr.	Robert D. Powers
Thomas A. Fanning	C. Dowd Ritter
John D. Johns	James H. Sanford
Patricia M. King	John Cox Webb, IV

By: /s/Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)

Date: February 27, 2013

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GEORGIA POWER COMPANY
SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

GEORGIA POWER COMPANY

By: W. Paul Bowers
President and Chief Executive Officer

By: /s/Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)

Date: February 27, 2013

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

W. Paul Bowers
President, Chief Executive Officer, and Director
(Principal Executive Officer)

Ronnie R. Labrato
Executive Vice President, Chief Financial Officer, and Treasurer
(Principal Financial Officer)

Ann P. Daiss
Vice President, Comptroller, and Chief Accounting Officer
(Principal Accounting Officer)

Directors:

Robert L. Brown, Jr.	Charles K. Tarbutton
Anna R. Cablik	Beverly Daniel Tatum
Thomas A. Fanning	D. Gary Thompson
Stephen S. Green	Clyde C. Tuggle
Jimmy C. Tallent	Richard W. Ussery

By: /s/Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)

Date: February 27, 2013

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GULF POWER COMPANY
SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

GULF POWER COMPANY

By:	S. W. Connally, Jr. President and Chief Executive Officer
By:	/s/Melissa K. Caen (Melissa K. Caen, Attorney-in-fact)
Date:	February 27, 2013

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

S. W. Connally, Jr.
President, Chief Executive Officer, and Director
(Principal Executive Officer)

Richard S. Teel
Vice President and Chief Financial Officer
(Principal Financial Officer)

Constance J. Erickson
Comptroller
(Principal Accounting Officer)

Directors:

Allan G. Bense Deborah H. Calder William C. Cramer, Jr.	J. Mort O'Sullivan, III Winston E. Scott

By: /s/Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)
Date: February 27, 2013

MISSISSIPPI POWER COMPANY
SIGNATURES
Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.
MISSISSIPPI POWER COMPANY

By:	Edward Day, VI President and Chief Executive Officer
By:	/s/Melissa K. Caen (Melissa K. Caen, Attorney-in-fact)
Date:	February 27, 2013

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Edward Day, VI
President, Chief Executive Officer, and Director
(Principal Executive Officer)

Moses H. Feagin
Vice President, Treasurer, and
Chief Financial Officer
(Principal Financial Officer)

Cynthia F. Shaw
Comptroller
(Principal Accounting Officer)
Directors:
Carl J. Chaney
L. Royce Cumbest
Christine L. Pickering
Phillip J. Terrell
M. L. Waters
By: /s/Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)
Date: February 27, 2013

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SOUTHERN POWER COMPANY
SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

SOUTHERN POWER COMPANY

By:	Oscar C. Harper IV President and Chief Executive Officer
By:	/s/Melissa K. Caen (Melissa K. Caen, Attorney-in-fact)
Date:	February 27, 2013

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Oscar C. Harper IV
President, Chief Executive Officer, and Director
(Principal Executive Officer)

Michael W. Southern
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

Janet J. Hodnett
Comptroller and Corporate Secretary
(Principal Accounting Officer)

Directors:

Art P. Beattie	
Mark A. Crosswhite	G. Edison Holland, Jr.
Thomas A. Fanning	Christopher C. Womack

By: /s/Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)
Date: February 27, 2013

Supplemental Information to be Furnished With Reports Filed Pursuant to Section 15(d) of the Act by Registrants Which Have Not Registered Securities Pursuant to Section 12 of the Act:

No annual report, proxy statement, form of proxy or other proxy soliciting material has been sent to security holders of the registrant during the period covered by this Annual Report on Form 10-K for the fiscal year ended December 31, 2012.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Southern Company

We have audited the consolidated financial statements of Southern Company and Subsidiaries (the "Company") as of December 31, 2012 and 2011, and for each of the three years in the period ended December 31, 2012, and the Company's internal control over financial reporting as of December 31, 2012, and have issued our report thereon dated February 27, 2013; such report is included elsewhere in this Form 10-K. Our audits also included the consolidated financial statement schedule of the Company (page S-2) listed in Item 15. This consolidated financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 27, 2013

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Alabama Power Company

We have audited the financial statements of Alabama Power Company (the "Company") as of December 31, 2012 and 2011, and for each of the three years in the period ended December 31, 2012, and have issued our report thereon dated February 27, 2013; such report is included elsewhere in this Form 10-K. Our audits also included the financial statement schedule of the Company (Page S-3) listed in Item 15. This financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP
Birmingham, Alabama
February 27, 2013

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Georgia Power Company

We have audited the financial statements of Georgia Power Company (the "Company") as of December 31, 2012 and 2011, and for each of the three years in the period ended December 31, 2012, and have issued our report thereon dated February 27, 2013; such report is included elsewhere in this Form 10-K. Our audits also included the financial statement schedule of the Company (Page S-4) listed in Item 15. This financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 27, 2013

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Gulf Power Company

We have audited the financial statements of Gulf Power Company (the "Company") as of December 31, 2012 and 2011, and for each of the three years in the period ended December 31, 2012, and have issued our report thereon dated February 27, 2013; such report is included elsewhere in this Form 10-K. Our audits also included the financial statement schedule of the Company (Page S-5) listed in Item 15. This financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 27, 2013

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Mississippi Power Company

We have audited the financial statements of Mississippi Power Company (the "Company") as of December 31, 2012 and 2011, and for each of the three years in the period ended December 31, 2012, and have issued our report thereon dated February 27, 2013; such report is included elsewhere in this Form 10-K. Our audits also included the financial statement schedule of the Company (Page S-6) listed in Item 15. This financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 27, 2013

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INDEX TO FINANCIAL STATEMENT SCHEDULES

Schedules I through V not listed above are omitted as not applicable or not required. A Schedule II for Southern Power Company and Subsidiary Companies is not being provided because there were no reportable items for the three-year period ended December 31, 2012. Columns omitted from schedules filed have been omitted because the information is not applicable or not required.

THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2012, 2011, AND 2010
(Stated in Thousands of Dollars)

Description	Balance at Beginning of Period	Additions: Charged to Income	Additions: Charged to Other Accounts	Deductions (Note)	Balance at End of Period
Provision for uncollectible accounts					
2012	$26,155	$35,305	$—	$44,476	$16,984
2011	24,919	66,641	—	65,405	26,155
2010	24,568	62,137	—	61,786	24,919

(Note) Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.

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ALABAMA POWER COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2012, 2011, AND 2010
(Stated in Thousands of Dollars)

Description	Balance at Beginning of Period	Additions		Deductions (Note)	Balance at End of Period
		Charged to Income	Charged to Other Accounts		
Provision for uncollectible accounts					
2012	$9,856	$10,537	$—	$11,943	$8,450
2011	9,602	16,415	—	16,161	9,856
2010	9,551	18,271	—	18,220	9,602

(Note) Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.

GEORGIA POWER COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2012, 2011, AND 2010
(Stated in Thousands of Dollars)

		Additions			
Description	Balance at Beginning of Period	Charged to Income	Charged to Other Accounts	Deductions (Note)	Balance at End of Period
Provision for uncollectible accounts					
2012	$13,038	$20,995	$—	$27,774	$6,259
2011	11,098	45,267	—	43,327	13,038
2010	9,856	37,004	—	35,762	11,098

(Note) Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.

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GULF POWER COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2012, 2011, AND 2010
(Stated in Thousands of Dollars)

Description	Balance at Beginning of Period	Additions		Deductions (Note)	Balance at End of Period
		Charged to Income	Charged to Other Accounts		
Provision for uncollectible accounts					
2012	$1,962	$2,611	$—	$3,083	$1,490
2011	2,014	3,332	—	3,384	1,962
2010	1,913	3,907	—	3,806	2,014

(Note) Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.

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MISSISSIPPI POWER COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2012, 2011, AND 2010
(Stated in Thousands of Dollars)

Description	Balance at Beginning of Period	Additions		Deductions (Note)	Balance at End of Period
		Charged to Income	Charged to Other Accounts		
Provision for uncollectible accounts					
2012	$547	$628	$—	$802	$373
2011	638	1,235	—	1,326	547
2010	940	1,519	—	1,821	638

(Note) Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.

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EXHIBIT INDEX

The exhibits below with an asterisk (*) preceding the exhibit number are filed herewith. The remaining exhibits have previously been filed with the SEC and are incorporated herein by reference. The exhibits marked with a pound sign (#) are management contracts or compensatory plans or arrangements required to be identified as such by Item 15 of Form 10-K.

(2) Plan of acquisition, reorganization, arrangement, liquidation or succession

Mississippi Power

(e)	1	—	Assignment and Assumption Agreement dated as of October 20, 2011, between Mississippi Power and Juniper Capital L.P. (Designated in Form 8-K dated October 20, 2011, File No. 001-11229, as Exhibit 2.1.)
(e)	2	—	Bond Assumption and Exchange Agreement, dated as of October 20, 2011, by and among Mississippi Business Finance Corporation, Mississippi Power, and the bondholders parties thereto. (Designated in Form 8-K dated October 20, 2011, File No. 001-11229, as Exhibit 2.2.)

(3) Articles of Incorporation and By-Laws

Southern Company

(a)	1	—	Composite Certificate of Incorporation of Southern Company, reflecting all amendments thereto through May 27, 2010. (Designated in Registration No. 33-3546 as Exhibit 4(a), in Certificate of Notification, File No. 70-7341, as Exhibit A, in Certificate of Notification, File No. 70-8181, as Exhibit A, and in Form 8-K dated May 26, 2010, File No. 1-3526, as Exhibit 3.1.)
(a)	2	—	By-laws of Southern Company as amended effective February 11, 2013, and as presently in effect. (Designated in Form 8-K dated February 11, 2013, File No. 1-3526, as Exhibit 3.1.)

Alabama Power

(b)	1	—	Charter of Alabama Power and amendments thereto through April 25, 2008. (Designated in Registration Nos. 2-59634 as Exhibit 2(b), 2-60209 as Exhibit 2(c), 2-60484 as Exhibit 2(b), 2-70838 as Exhibit 4(a)-2, 2-85987 as Exhibit 4(a)-2, 33-25539 as Exhibit 4(a)-2, 33-43917 as Exhibit 4(a)-2, in Form 8-K dated February 5, 1992, File No. 1-3164, as Exhibit 4(b)-3, in Form 8-K dated July 8, 1992, File No. 1-3164, as Exhibit 4(b)-3, in Form 8-K dated October 27, 1993, File No. 1-3164, as Exhibits 4(a) and 4(b), in Form 8-K dated November 16, 1993, File No. 1-3164, as Exhibit 4(a), in Certificate of Notification, File No. 70-8191, as Exhibit A, in Alabama Power's Form 10-K for the year ended December 31, 1997, File No. 1-3164, as Exhibit 3(b)2, in Form 8-K dated August 10, 1998, File No. 1-3164, as Exhibit 4.4, in Alabama Power's Form 10-K for the year ended December 31, 2000, File No. 1-3164, as Exhibit 3(b)2, in Alabama Power's Form 10-K for the year ended December 31, 2001, File No. 1-3164, as Exhibit 3(b)2, in Form 8-K dated February 5, 2003, File No. 1-3164, as Exhibit 4.4, in Alabama Power's Form 10-Q for the quarter ended March 31, 2003, File No 1-3164, as Exhibit 3(b)1, in Form 8-K dated February 5, 2004, File No. 1-3164, as Exhibit 4.4, in Alabama Power's Form 10-Q for the quarter ended March 31, 2006, File No. 1-3164, as Exhibit 3(b)(1), in Form 8-K dated December 5, 2006, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated September 12, 2007, File No. 1-3164, as Exhibit 4.5, in Form 8-K dated October 17, 2007, File No. 1-3164, as Exhibit 4.5, and in Alabama Power's Form 10-Q for the quarter ended March 31, 2008, File No. 1-3164, as Exhibit 3(b)1.)
(b)	2	—	

			By-laws of Alabama Power as amended effective April 22, 2011, and as presently in effect. (Designated in Form 8-K dated April 22, 2011, File No 1-3164, as Exhibit 3.1.)
Georgia Power			
(c)	1	—	Charter of Georgia Power and amendments thereto through October 9, 2007. (Designated in Registration Nos. 2-63392 as Exhibit 2(a)-2, 2-78913 as Exhibits 4(a)-(2) and 4(a)-(3), 2-93039 as Exhibit 4(a)-(2), 2-96810 as Exhibit 4(a)-2, 33-141 as Exhibit 4(a)-(2), 33-1359 as Exhibit 4(a)(2), 33-5405 as Exhibit 4(b)(2), 33-14367 as Exhibits 4(b)-(2) and 4(b)-(3), 33-22504 as Exhibits 4(b)-(2), 4(b)-(3) and 4(b)-(4), in Georgia Power's Form 10-K for the year ended December 31, 1991, File No. 1-6468, as Exhibits 4(a)(2) and 4(a)(3), in Registration No. 33-48895 as Exhibits 4(b)-(2) and 4(b)-(3), in Form 8-K dated December 10, 1992, File No. 1-6468 as Exhibit 4(b), in Form 8-K dated June 17, 1993, File No. 1-6468, as Exhibit 4(b), in Form 8-K dated October 20, 1993, File No. 1-6468, as Exhibit 4(b), in Georgia Power's Form 10-K for the year ended December 31, 1997, File No. 1-6468, as Exhibit 3(c)2, in Georgia Power's Form 10-K for the year ended December 31, 2000, File No. 1-6468, as Exhibit 3(c)2, in Form 8-K dated June 27, 2006, File No. 1-6468, as Exhibit 3.1, and in Form 8-K dated October 3, 2007, File No. 1-6468, as Exhibit 4.5.)
(c)	2	—	By-laws of Georgia Power as amended effective May 20, 2009, and as presently in effect. (Designated in Form 8-K dated May 20, 2009, File No. 1-6468, as Exhibit 3(c)2.)

Gulf Power

(d)	1	—	Amended and Restated Articles of Incorporation of Gulf Power and amendments thereto through October 17, 2007. (Designated in Form 8-K dated October 27, 2005, File No. 0-2429, as Exhibit 3.1, in Form 8-K dated November 9, 2005, File No. 0-2429, as Exhibit 4.7, and in Form 8-K dated October 16, 2007, File No. 0-2429, as Exhibit 4.5.)
(d)	2	—	By-laws of Gulf Power as amended effective November 2, 2005, and as presently in effect. (Designated in Form 8-K dated November 2, 2005, File No. 0-2429, as Exhibit 3.2.)

Mississippi Power

(e)	1	—	Articles of Incorporation of Mississippi Power, articles of merger of Mississippi Power Company (a Maine corporation) into Mississippi Power and articles of amendment to the articles of incorporation of Mississippi Power through April 2, 2004. (Designated in Registration No. 2-71540 as Exhibit 4(a)-1, in Form U5S for 1987, File No. 30-222-2, as Exhibit B-10, in Registration No. 33-49320 as Exhibit 4(b)-(1), in Form 8-K dated August 5, 1992, File No. 001-11229, as Exhibits 4(b)-2 and 4(b)-3, in Form 8-K dated August 4, 1993, File No. 001-11229, as Exhibit 4(b)-3, in Form 8-K dated August 18, 1993, File No. 001-11229, as Exhibit 4(b)-3, in Mississippi Power's Form 10-K for the year ended December 31, 1997, File No. 001-11229, as Exhibit 3(e)2, in Mississippi Power's Form 10-K for the year ended December 31, 2000, File No. 001-11229, as Exhibit 3(e)2, and in Form 8-K dated March 3, 2004, File No. 001-11229, as Exhibit 4.6.)
(e)	2	—	By-laws of Mississippi Power as amended effective February 28, 2001, and as presently in effect. (Designated in Mississippi Power's Form 10-K for the year ended December 31, 2001, File No. 001-11229, as Exhibit 3(e)2.)

Southern Power

(f)	1	—	Certificate of Incorporation of Southern Power dated January 8, 2001. (Designated in Registration No. 333-98553 as Exhibit 3.1.)
(f)	2	—	By-laws of Southern Power effective January 8, 2001. (Designated in Registration No. 333-98553 as Exhibit 3.2.)

(4) Instruments Describing Rights of Security Holders, Including Indentures

With respect to each of Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power, such registrant has not included any instrument with respect to long-term debt that does not exceed 10% of the total assets of such registrant and its subsidiaries. Each such registrant agrees, upon request of the SEC, to furnish copies of any or all such instruments to the SEC.

Southern Company

(a)	1	—	Senior Note Indenture dated as of January 1, 2007, between Southern Company and Wells Fargo Bank, National Association, as Trustee, and indentures supplemental thereto through August 23, 2011. (Designated in Form 8-K dated January 11, 2006, File No. 1-3526, as Exhibits 4.1 and 4.2, in Form 8-K dated March 20, 2007, File No. 1-3526, as Exhibit 4.2, in Form 8-K dated August 13, 2008, File No. 1-3526, as Exhibit 4.2, in Form 8-K dated May 11, 2009, File No. 1-3526, as Exhibit 4.2, in Form 8-K dated October 19, 2009, File No. 1-3526, as Exhibit 4.2, in Form 8-K dated September 13, 2010, File No. 1-3526, as Exhibit 4.2, and in Form 8-K dated August 16, 2011, File No. 1-3526, as Exhibit 4.2.)

Alabama Power

(b)	1	—	

Subordinated Note Indenture dated as of January 1, 1997, between Alabama Power and The Bank of New York Mellon (as successor to JPMorgan Chase Bank, N.A. (formerly known as The Chase Manhattan Bank)), as Trustee, and indentures supplemental thereto through October 2, 2002. (Designated in Form 8-K dated January 9, 1997, File No. 1-3164, as Exhibits 4.1 and 4.2, in Form 8-K dated February 18, 1999, File No. 1-3164, as Exhibit 4.2, and in Form 8-K dated September 26, 2002, File No. 3164, as Exhibits 4.9-A and 4.9-B.)

(b)	2	—	Senior Note Indenture dated as of December 1, 1997, between Alabama Power and The Bank of New York Mellon (as successor to JPMorgan Chase Bank, N.A. (formerly known as The Chase Manhattan Bank)), as Trustee, and indentures supplemental thereto through December 5, 2012. (Designated in Form 8-K dated December 4, 1997, File No. 1-3164, as Exhibits 4.1 and 4.2, in Form 8-K dated February 20, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated April 17, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated August 11, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated September 8, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated September 16, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated October 7, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated October 28, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated November 12, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated May 19, 1999, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated August 13, 1999, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated September 21, 1999, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated May 11, 2000, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated August 22, 2001, File No. 1-3164, as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated June 21, 2002, File No. 1-3164, as Exhibit 4.2(a), in Form 8-K dated October 16, 2002, File No. 1-3164, as Exhibit 4.2(a), in Form 8-K dated November 20, 2002, File No. 1-3164, as Exhibit 4.2(a), in Form 8-K dated December 6, 2002, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated February 11, 2003, File No. 1-3164, as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated March 12, 2003, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated April 15, 2003, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated May 1, 2003, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated November 14, 2003, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated February 10, 2004, File No. 1-3164, as Exhibit 4.2 in Form 8-K dated April 7, 2004, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated August 19, 2004, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated November 9, 2004, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated March 8, 2005, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated January 11, 2006, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated January 13, 2006, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated February 1, 2006, File No. 1-3164, as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated March 9, 2006, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated June 7, 2006, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated January 30, 2007, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated April 4, 2007, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated October 11, 2007, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated December 4, 2007, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated May 8, 2008, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated November 14, 2008, File No. 1-3164 as Exhibit 4.2, in Form 8-K dated February 26, 2009, File No. 1-3164 as Exhibit 4.2, in Form 8-K dated September 27, 2010, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated March 3, 2011, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated May 18, 2011, File No. 1-3164, as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated January 10, 2012, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated October 9, 2012, File No. 1-3164, as Exhibit 4.2, and in Form 8-K dated November 27, 2012, File No. 1-3164, as Exhibit 4.2.)
(b)	3	—	Amended and Restated Trust Agreement of Alabama Power Capital Trust V dated as of September 1, 2002. (Designated in Form 8-K dated September 26, 2002, File No. 1-3164, as Exhibit 4.12-B.)

(b)	4	—	Guarantee Agreement relating to Alabama Power Capital Trust V dated as of September 1, 2002. (Designated in Form 8-K dated September 26, 2002, File No. 1-3164, as Exhibit 4.16-B.)

Georgia Power

(c) 1 — Senior Note Indenture dated as of January 1, 1998, between Georgia Power and The Bank of New York Mellon (as successor to JPMorgan Chase Bank, N.A. (formerly known as The Chase Manhattan Bank)), as Trustee, and indentures supplemental thereto through November 15, 2012. (Designated in Form 8-K dated January 21, 1998, File No. 1-6468, as Exhibits 4.1 and 4.2, in Forms 8-K each dated November 19, 1998, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated March 3, 1999, File No. 1-6469 as Exhibit 4.2, in Form 8-K dated February 15, 2000, File No. 1-6469 as Exhibit 4.2, in Form 8-K dated January 26, 2001, File No. 1-6469 as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated February 16, 2001, File No. 1-6469 as Exhibit 4.2, in Form 8-K dated May 1, 2001, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated June 27, 2002, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated November 15, 2002, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated February 13, 2003, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated February 21, 2003, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated April 10, 2003, File No. 1-6468, as Exhibits 4.1, 4.2 and 4.3, in Form 8-K dated September 8, 2003, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated September 23, 2003, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated January 12, 2004, File No. 1-6468, as Exhibits 4.1 and 4.2, in Form 8-K dated February 12, 2004, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated August 11, 2004, File No. 1-6468, as Exhibits 4.1 and 4.2, in Form 8-K dated January 13, 2005, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated April 12, 2005, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated November 30, 2005, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated December 8, 2006, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated March 6, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated June 4, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated June 18, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated July 10, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated August 24, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated November 29, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated March 12, 2008, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated June 5, 2008, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated November 12, 2008, File No. 1-6468, as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated February 4, 2009, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated December 8, 2009, File No. 1-6468, as Exhibit 4.2, and in Form 8-K dated March 9, 2010, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated May 24, 2010, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated August 26, 2010, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated September 20, 2010, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated January 13, 2011, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated April 12, 2011, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated February 29, 2012, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated May 8, 2012, File No. 1-6468, as Exhibit 4.2(b), in Form 8-K dated August 7, 2012, File No. 1-6468, as Exhibit 4.2, and in Form 8-K dated November 8, 2012, File No. 1-6468, as Exhibit 4.2.)

(c) 2 — Senior Note Indenture dated as of March 1, 1998 between Georgia Power, as successor to Savannah Electric, and The Bank of New York Mellon (as successor to JPMorgan Chase Bank, N.A. (formerly known as The Chase Manhattan Bank)), as Trustee, and indentures supplemental thereto through June 30, 2006. (Designated in Form 8-K dated March 9, 1998, File No. 1-5072, as Exhibits 4.1 and 4.2, in Form 8-K dated May 8, 2001, File No. 1-5072, as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated

March 4, 2002, File No. 1-5072, as Exhibit 4.2, in Form 8-K dated November 4, 2002, File No. 1-5072, as Exhibit 4.2, in Form 8-K dated December 10, 2003, File No. 1-5072, as Exhibits 4.1 and 4.2, in Form 8-K dated December 2, 2004, File No. 1-5072, as Exhibit 4.1, and in Form 8-K dated June 27, 2006, File No. 1-6468, as Exhibit 4.2.)

Gulf Power

(d) 1 — Senior Note Indenture dated as of January 1, 1998, between Gulf Power and The Bank of New York Mellon (as successor to JPMorgan Chase Bank, N.A. (formerly known as The Chase Manhattan Bank)), as Trustee, and indentures supplemental thereto through May 18, 2012. (Designated in Form 8-K dated June 17, 1998, File No. 0-2429, as Exhibits 4.1 and 4.2, in Form 8-K dated August 17, 1999, File No. 0-2429, as Exhibit 4.2, in Form 8-K dated July 31, 2001, File No. 0-2429, as Exhibit 4.2, in Form 8-K dated October 5, 2001, File No. 0-2429, as Exhibit 4.2, in Form 8-K dated January 18, 2002, File No. 0-2429, as Exhibit 4.2, in Form 8-K dated March 21, 2003, File No. 0-2429, as Exhibit 4.2, in Form 8-K dated July 10, 2003, File No. 001-31737, as Exhibits 4.1 and 4.2, in Form 8-K dated September 5, 2003, File No. 001-31737, as Exhibit 4.1, in Form 8-K dated April 6, 2004, File No. 001-31737, as Exhibit 4.1, in Form 8-K dated September 13, 2004, File No. 001-31737, as Exhibit 4.1, in Form 8-K dated August 11, 2005, File No. 001-31737, as Exhibit 4.1, in Form 8-K dated October 27, 2005, File No. 001-31737, as Exhibit 4.1, in Form 8-K dated November 28, 2006, File No. 001-31737, as Exhibit 4.2, in Form 8-K dated June 5, 2007, File No. 001-31737, as Exhibit 4.2, in Form 8-K dated June 22, 2009, File No. 001-31737, as Exhibit 4.2, in Form 8-K dated April 6, 2010, File No. 001-31737, as Exhibit 4.2, in Form 8-K dated September 9, 2010, File No. 001-31737, as Exhibit 4.2, in Form 8-K dated May 12, 2011, File No. 001-31737, as Exhibit 4.2, and in Form 8-K dated May 15, 2012, File No. 001-31737, as Exhibit 4.2.)

Mississippi Power

(e) 1 — Senior Note Indenture dated as of May 1, 1998 between Mississippi Power and Wells Fargo Bank, National Association, as Successor Trustee, and indentures supplemental thereto through March 9, 2012. (Designated in Form 8-K dated May 14, 1998, File No. 001-11229, as Exhibits 4.1, 4.2(a) and 4.2(b), in Form 8-K dated March 22, 2000, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated March 12, 2002, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated April 24, 2003, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated March 3, 2004, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated June 24, 2005, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated November 8, 2007, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated November 14, 2008, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated March 3, 2009, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated October 11, 2011, File No. 001-11229, as Exhibits 4.2(a) and 4.2(b), and in Form 8-K dated March 5, 2012, File No. 001-11229, as Exhibit 4.2(b).)

Southern Power

(f) 1 — Senior Note Indenture dated as of June 1, 2002, between Southern Power and The Bank of New York Mellon (formerly known as The Bank of New York), as Trustee, and indentures supplemental thereto through September 22, 2011. (Designated in Registration No. 333-98553 as Exhibits 4.1 and 4.2 and in Southern Power's Form 10-Q for the quarter ended June 30, 2003, File No. 333-98553, as Exhibit 4(g)1, in Form 8-K dated November 13, 2006, File No. 333-98553, as Exhibit 4.2, and in Form 8-K dated September 14, 2011, File No. 333-98553, as Exhibit 4.4.)

(10) Material Contracts

Southern Company

(a) 1 —

				Southern Company 2011 Omnibus Incentive Compensation Plan, effective May 25, 2011. (Designated in Southern Company's Form 8-K dated May 25, 2011, File No. 1-3526, as Exhibit 10.1.)
#	(a)	2	—	Form of Stock Option Award Agreement for Executive Officers of Southern Company under the Southern Company Omnibus Incentive Compensation Plan. (Designated in Southern Company's Form 10-Q for the quarter ended March 31, 2011, File No. 1-3526, as Exhibit 10(a)3.)
#	(a)	3	—	Deferred Compensation Plan for Directors of The Southern Company, Amended and Restated effective January 1, 2008. (Designated in Southern Company's Form 10-K for the year ended December 31, 2007, File No. 1-3526, as Exhibit 10(a)3.)
#	(a)	4	—	Southern Company Deferred Compensation Plan as amended and restated as of January 1, 2009 and First Amendment thereto effective January 1, 2010. (Designated in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)4 and in Southern Company's Form 10-K for the year ended December 31, 2009, File No. 1-3526, as Exhibit 10(a)5.)
#	(a)	5	—	Outside Directors Stock Plan for The Southern Company and its Subsidiaries, effective May 26, 2004. (Designated in Southern Company's Form 10-Q for the quarter ended June 30, 2004, File No. 1-3526, as Exhibit 10(a)2.)

#	(a)	6	—	The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective January 1, 2009 and First Amendment thereto effective January 1, 2010. (Designated in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)6 and in Southern Company's Form 10-K for the year ended December 31, 2009, File No. 1-3526, as Exhibit 10(a)(8).)
#	(a)	7	—	The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of January 1, 2009 and First Amendment thereto effective January 1, 2010. (Designated in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)7 and in Southern Company's Form 10-K for the year ended December 31, 2009, File No. 1-3526, as Exhibit 10(a)10.)
#	(a)	8	—	Consulting Agreement by and with Southern Company Services, Inc. and Anthony J. Topazi effective August 1, 2012. (Designated in Southern Company's Form 10-Q for the quarter ended June 30, 2012, File No. 1-3526, as Exhibit 10(a)2.)
#	(a)	9	—	Retention and Restricted Stock Unit Award Agreement by and between Southern Company and Charles D. McCrary effective May 22, 2012. (Designated in Southern Company's Form 10-Q for the quarter ended June 30, 2012, File No. 1-3526, as Exhibit 10(a)1.)
#	(a)	10	—	The Southern Company Change in Control Benefits Protection Plan, effective December 31, 2008. (Designated in Form 8-K dated December 31, 2008, File No. 1-3526, as Exhibit 10.1.)
#	(a)	11	—	Southern Company Deferred Compensation Trust Agreement as amended and restated effective January 1, 2001 between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, SouthernLINC Wireless, Southern Company Energy Solutions, LLC, and Southern Nuclear and First Amendment thereto effective January 1, 2009. (Designated in Southern Company's Form 10-K for the year ended December 31, 2000, File No. 1-3526, as Exhibit 10(a)103 and in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)16.)
#	(a)	12	—	Deferred Stock Trust Agreement for Directors of Southern Company and its subsidiaries, dated as of January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. (Designated in Southern Company's Form 10-K for the year ended December 31, 2000, File No. 1-3526, as Exhibit 10(a)104 and in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)18.)
#	(a)	13	—	Amended and Restated Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its subsidiaries, effective September 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. (Designated in Southern Company's Form 10-K for the year ended December 31, 2001, File No. 1-3526, as Exhibit 10(a)92 and in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)20.)
#	(a)	14	—	Amended and Restated Southern Company Senior Executive Change in Control Severance Plan effective December 31, 2008, First Amendment thereto effective January 1, 2010, and Second Amendment thereto effective February 23, 2011.

				(Designated in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)23, in Southern Company's Form 10-K for the year ended December 31, 2009, File No. 1-3526, as Exhibit 10(a)22, and in Southern Company's Form 10-K for the year ended December 31, 2010, File No. 1-3526, as Exhibit 10(a)16.)
#	(a)	15	—	Southern Company Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008 and First Amendment thereto effective January 1, 2010. (Designated in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)24 and in Southern Company's Form 10-K for the year ended December 31, 2009, File No. 1-3526, as Exhibit 10(a)24.)
# *	(a)	16	—	Base Salaries of Named Executive Officers.
#	(a)	17	—	Summary of Non-Employee Director Compensation Arrangements. (Designated in Form 10-Q for the quarter ended March 31, 2011, File No. 1-3526, as Exhibit 10(a)5.)
#	(a)	18	—	Form of Terms for Performance Share Awards granted under the Southern Company Omnibus Incentive Compensation Plan. (Designated in Form 8-K dated February 9, 2010, File No. 1-3526, as Exhibit 10.1.)
#	(a)	19	—	Restricted Stock Award Agreement between Southern Company and W. Paul Bowers dated July 27, 2010. (Designated in Form 10-Q for the quarter ended September 30, 2010, File No. 1-3526, as Exhibit 10(a)2.)

Alabama Power

	(b)	1	—	Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power, and SCS. (Designated in Form 10-Q for the quarter ended March 31, 2007, File No. 1-3164, as Exhibit 10(b)5.)
#	(b)	2	—	Southern Company 2011 Omnibus Incentive Compensation Plan, effective May 25, 2011. See Exhibit 10(a)1 herein.
#	(b)	3	—	Form of Stock Option Award Agreement for Executive Officers of Southern Company under the Southern Company Omnibus Incentive Compensation Plan. See Exhibit 10(a)2 herein.
#	(b)	4	—	Southern Company Deferred Compensation Plan as amended and restated as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)4 herein.
#	(b)	5	—	Outside Directors Stock Plan for The Southern Company and its Subsidiaries, effective May 26, 2004. See Exhibit 10(a)5 herein.
#	(b)	6	—	The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)6 herein.
#	(b)	7	—	The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)7 herein.
#	(b)	8	—	Southern Company Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)15 herein.
#	(b)	9	—	Deferred Compensation Plan for Directors of Alabama Power Company, Amended and Restated effective January 1, 2008. (Designated in Alabama Power's Form 10-Q for the quarter ended June 30, 2008, File No. 1-3164, as Exhibit 10(b)1.)
#	(b)	10	—	The Southern Company Change in Control Benefits Protection Plan, effective December 31, 2008. See Exhibit 10(a)10 herein.
#	(b)	11	—	Southern Company Deferred Compensation Trust Agreement as amended and restated effective January 1, 2001 between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, SouthernLINC Wireless, Southern Company Energy Solutions, LLC, and Southern Nuclear and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)11 herein.
#	(b)	12	—	Deferred Stock Trust Agreement for Directors of Southern Company and its subsidiaries, dated as of January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)12 herein.
#	(b)	13	—	Amended and Restated Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its subsidiaries, effective September 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)13 herein.
#	(b)	14	—	Amended and Restated Southern Company Senior Executive Change in Control Severance Plan effective December 31, 2008, First Amendment thereto effective January 1, 2010, and Second Amendment thereto effective February 23, 2011. See

				Exhibit 10(a)14 herein.
# *	(b)	15	—	Base Salaries of Named Executive Officers.
#	(b)	16	—	Summary of Non-Employee Director Compensation Arrangements. (Designated in Alabama Power's Form 10-Q for the quarter ended June 30, 2010, File No. 1-3164, as Exhibit 10(b)1.)
#	(b)	17	—	Form of Terms for Performance Share Awards granted under the Southern Company Omnibus Incentive Compensation Plan. See Exhibit 10(a)18 herein.
#	(b)	18	—	Deferred Compensation Agreement between Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and SCS and Philip C. Raymond dated September 15, 2010. (Designated in Alabama Power's Form 10-Q for the quarter ended September 30, 2010, File No. 1-3164, as Exhibit 10(b)2.)
#	(b)	19		Retention and Restricted Stock Unit Award Agreement by and between Southern Company and Charles D. McCrary effective May 22, 2012. See Exhibit 10(a)9 herein.
Georgia Power				
	(c)	1	—	Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power, and SCS. See Exhibit 10(b)1 herein.

	(c)	2	—	Revised and Restated Integrated Transmission System Agreement dated as of November 12, 1990, between Georgia Power and OPC. (Designated in Georgia Power's Form 10-K for the year ended December 31, 1990, File No. 1-6468, as Exhibit 10(g).)
	(c)	3	—	Revised and Restated Integrated Transmission System Agreement between Georgia Power and Dalton dated as of December 7, 1990. (Designated in Georgia Power's Form 10-K for the year ended December 31, 1990, File No. 1-6468, as Exhibit 10(gg).)
	(c)	4	—	Revised and Restated Integrated Transmission System Agreement between Georgia Power and MEAG Power dated as of December 7, 1990. (Designated in Georgia Power's Form 10-K for the year ended December 31, 1990, File No. 1-6468, as Exhibit 10(hh).)
#	(c)	5	—	Southern Company 2011 Omnibus Incentive Compensation Plan, effective May 25, 2011. See Exhibit 10(a)1 herein.
#	(c)	6	—	Form of Stock Option Award Agreement for Executive Officers of Southern Company under the Southern Company Omnibus Incentive Compensation Plan. See Exhibit 10(a)2 herein.
#	(c)	7	—	Southern Company Deferred Compensation Plan as amended and restated as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)4 herein.
#	(c)	8	—	Outside Directors Stock Plan for The Southern Company and its Subsidiaries, effective May 26, 2004. See Exhibit 10(a)5 herein.
#	(c)	9	—	The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)6 herein.
#	(c)	10	—	The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)7 herein.
#	(c)	11	—	Southern Company Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)15 herein.
#	(c)	12	—	Deferred Compensation Plan For Directors of Georgia Power Company, Amended and Restated Effective January 1, 2008. (Designated in Form 10-K for the year ended December 31, 2007, File No. 1-6468, as Exhibit 10(c)12.)
#	(c)	13	—	The Southern Company Change in Control Benefits Protection Plan, effective December 31, 2008. See Exhibit 10(a)10 herein.
#	(c)	14	—	Southern Company Deferred Compensation Trust Agreement as amended and restated effective January 1, 2001 between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, SouthernLINC Wireless, Southern Company Energy Solutions, LLC, and Southern Nuclear and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)11 herein.
#	(c)	15	—	Deferred Stock Trust Agreement for Directors of Southern Company and its subsidiaries, dated as of January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)12 herein.
#	(c)	16	—	

				Amended and Restated Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its subsidiaries, effective September 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)13 herein.
#	(c)	17	—	Amended and Restated Southern Company Senior Executive Change in Control Severance Plan effective December 31, 2008, First Amendment thereto effective January 1, 2010, and Second Amendment thereto effective February 23, 2011. See Exhibit 10(a)14 herein.
# *	(c)	18	—	Base Salaries of Named Executive Officers.
#	(c)	19	—	Summary of Non-Employee Director Compensation Arrangements. (Designated in Georgia Power's Form 10-K for the year ended December 31, 2009, File No. 1-6468, as Exhibit 10(c)26.)

	(c)	20	—	Engineering, Procurement and Construction Agreement, dated as of April 8, 2008, between Georgia Power, for itself and as agent for OPC, MEAG Power, and Dalton, as owners, and a consortium consisting of Westinghouse Electric Company LLC and Stone & Webster, Inc., as contractor, for Units 3 & 4 at the Vogtle Electric Generating Plant Site, Amendment No. 1 thereto dated as of December 11, 2009, Amendment No. 2 thereto dated as of January 15, 2010, Amendment No. 3 thereto dated as of February 23, 2010, Amendment No. 4 thereto dated as of May 2, 2011, and Amendment No. 5 thereto dated as of February 7, 2012. (Georgia Power requested confidential treatment for certain portions of these documents pursuant to applications for confidential treatment sent to the SEC. Georgia Power omitted such portions from the filings and filed them separately with the SEC.) (Designated in Form 10-Q/A for the quarter ended June 30, 2008, File No. 1-6468, as Exhibit 10(c)1, in Form 10-K for the year ended December 31, 2009, File No. 1-6468, as Exhibit 10(c)29, in Georgia Power's Form 10-Q for the quarter ended March 31, 2010, File No. 1-6468, as Exhibits 10(c)1 and 10(c)2, in Georgia Power's Form 10-Q for the quarter ended June 30, 2011, File No. 1-6468, as Exhibit 10(c)2, and in Georgia Power's Form 10-Q for the quarter ended March 31, 2012, File No. 1-6468, as Exhibit 10(c)2.)
#	(c)	21	—	Form of Terms for Performance Share Awards granted under the Southern Company Omnibus Incentive Compensation Plan. See Exhibit 10(a)18 herein.
#	(c)	22	—	Restricted Stock Award Agreement between Southern Company and W. Paul Bowers dated July 27, 2010. See Exhibit 10(a)19 herein.
#	(c)	23	—	Retention Agreement between Georgia Power and Michael A. Brown, effective January 1, 2011. (Designated in Form 10-Q for the quarter ended March 31, 2011, File No. 1-6468, as Exhibit 10(c)1.)
# *	(c)	24	—	Retention Award Agreement between Southern Nuclear and Joseph A. Miller, effective January 1, 2013.
# *	(c)	25	—	Amendment to Retention Award Agreement between Southern Nuclear and Joseph A. Miller, effective January 1, 2013.
Gulf Power				
	(d)	1	—	Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power, and SCS. See Exhibit 10(b)1 herein.
#	(d)	2	—	Southern Company 2011 Omnibus Incentive Compensation Plan, effective May 25, 2011. See Exhibit 10(a)1 herein.
#	(d)	3	—	Form of Stock Option Award Agreement for Executive Officers of Southern Company under the Southern Company Omnibus Incentive Compensation Plan. See Exhibit 10(a)2 herein.
#	(d)	4	—	Southern Company Deferred Compensation Plan as amended and restated as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)4 herein.
#	(d)	5	—	Outside Directors Stock Plan for The Southern Company and its Subsidiaries, effective May 26, 2004. See Exhibit 10(a)5 herein.
#	(d)	6	—	The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)7 herein.
#	(d)	7	—	Southern Company Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008 and First Amendment thereto effective

				January 1, 2010. See Exhibit 10(a)15 herein.
#	(d)	8	—	The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)6 herein.
#	(d)	9	—	Deferred Compensation Plan For Outside Directors of Gulf Power Company, Amended and Restated effective January 1, 2008. (Designated in Gulf Power's Form 10-Q for the quarter ended March 31, 2008, File No. 0-2429, as Exhibit 10(d)1.)
#	(d)	10	—	The Southern Company Change in Control Benefits Protection Plan, effective December 31, 2008. See Exhibit 10(a)10 herein.
#	(d)	11	—	Southern Company Deferred Compensation Trust Agreement as amended and restated effective January 1, 2001 between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, SouthernLINC Wireless, Southern Company Energy Solutions, LLC, and Southern Nuclear and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)11 herein.

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#	(d)	12	—	Deferred Stock Trust Agreement for Directors of Southern Company and its subsidiaries, dated as of January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)12 herein.
#	(d)	13	—	Amended and Restated Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its subsidiaries, effective September 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)13 herein.
#	(d)	14	—	Amended and Restated Southern Company Senior Executive Change in Control Severance Plan effective December 31, 2008, First Amendment thereto effective January 1, 2010, and Second Amendment thereto effective February 23, 2011. See Exhibit 10(a)14 herein.
# *	(d)	15	—	Base Salaries of Named Executive Officers.
#	(d)	16	—	Summary of Non-Employee Director Compensation Arrangements. (Designated in Gulf Power's Form 10-Q for the quarter ended June 30, 2010, File No. 001-31737, as Exhibit 10(d)1.)
	(d)	17	—	Power Purchase Agreement between Gulf Power and Shell Energy North America (US), L.P. dated March 16, 2009. (Designated in Gulf Power's Form 10-Q for the quarter ended March 31, 2009, File No. 001-31737, as Exhibit 10(d)1.) (Gulf Power requested confidential treatment for certain portions of this document pursuant to an application for confidential treatment sent to the SEC. Gulf Power omitted such portions from this filing and filed them separately with the SEC.)
#	(d)	18	—	Form of Terms for Performance Share Awards granted under the Southern Company Omnibus Incentive Compensation Plan. See Exhibit 10(a)18 herein.
#	(d)	19	—	Deferred Compensation Agreement between Southern Company, Georgia Power, Gulf Power, and Southern Nuclear and Bentina C. Terry dated August 1, 2010. (Designated in Gulf Power's Form 10-Q for the quarter ended September 30, 2010, File No. 001-31737, as Exhibit 10(d)2.)
#	(d)	20	—	Deferred Compensation Agreement between Southern Company, Alabama Power, and SCS and Mark A. Crosswhite dated July 30, 2008. (Designated in Alabama Power's Form 10-K for the year ended December 31, 2009, File No. 1-3164, as Exhibit 10(b)21.)
Mississippi Power				
	(e)	1	—	Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power, and SCS. See Exhibit 10(b)1 herein.
	(e)	2	—	Transmission Facilities Agreement dated February 25, 1982, Amendment No. 1 dated May 12, 1982 and Amendment No. 2 dated December 6, 1983, between Entergy Corporation (formerly Gulf States) and Mississippi Power. (Designated in Mississippi Power's Form 10-K for the year ended December 31, 1981, File No. 001-11229, as Exhibit 10(f), in Mississippi Power's Form 10-K for the year ended December 31, 1982, File No. 001-11229, as Exhibit 10(f)(2), and in Mississippi Power's Form 10-K for the year ended December 31, 1983, File No. 001-11229, as Exhibit 10(f)(3).)
#	(e)	3	—	Southern Company 2011 Omnibus Incentive Compensation Plan, effective May 25, 2011. See Exhibit 10(a)1 herein.
#	(e)	4	—	

				Form of Stock Option Award Agreement for Executive Officers of Southern Company under the Southern Company Omnibus Incentive Compensation Plan. See Exhibit 10(a)2 herein.
#	(e)	5	—	Southern Company Deferred Compensation Plan as amended and restated as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)4 herein.
#	(e)	6	—	Outside Directors Stock Plan for The Southern Company and its Subsidiaries, effective May 26, 2004. See Exhibit 10(a)5 herein.
#	(e)	7	—	The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)7 herein.
#	(e)	8	—	Southern Company Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)15 herein.
#	(e)	9	—	The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)6 herein.

#	(e)	10	—	Deferred Compensation Plan for Outside Directors of Mississippi Power Company, Amended and Restated effective January 1, 2008. (Designated in Mississippi Power's Form 10-Q for the quarter ended March 31, 2008, File No. 001-11229 as Exhibit 10(e)1.)
#	(e)	11	—	The Southern Company Change in Control Benefits Protection Plan, effective December 31, 2008. See Exhibit 10(a)10 herein.
#	(e)	12	—	Southern Company Deferred Compensation Trust Agreement as amended and restated effective January 1, 2001 between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, SouthernLINC Wireless, Southern Company Energy Solutions, LLC, and Southern Nuclear and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)11 herein.
#	(e)	13	—	Deferred Stock Trust Agreement for Directors of Southern Company and its subsidiaries, dated as of January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)12 herein.
#	(e)	14	—	Amended and Restated Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its subsidiaries, effective September 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)13 herein.
#	(e)	15	—	Amended and Restated Southern Company Senior Executive Change in Control Severance Plan effective December 31, 2008 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)14 herein.
# *	(e)	16	—	Base Salaries of Named Executive Officers.
#	(e)	17	—	Summary of Non-Employee Director Compensation Arrangements. (Designated in Mississippi Power's Form 10-K for the year ended December 31, 2009, File No. 001-11229, as Exhibit 10(e)22.)
	(e)	18	—	Cooperative Agreement between the DOE and SCS dated as of December 12, 2008. (Designated in Mississippi Power's Form 10-K for the year ended December 31, 2008, File No. 001-11229, as Exhibit 10(e)22.) (Mississippi Power requested confidential treatment for certain portions of this document pursuant to an application for confidential treatment sent to the SEC. Mississippi Power omitted such portions from this filing and filed them separately with the SEC.)
#	(e)	19	—	Form of Terms for Performance Share Awards granted under the Southern Company Omnibus Incentive Compensation Plan. See Exhibit 10(a)18 herein.
Southern Power				
	(f)	1	—	Service contract dated as of January 1, 2001, between SCS and Southern Power. (Designated in Southern Company's Form 10-K for the year ended December 31, 2001, File No. 1-3526, as Exhibit 10(a)(2).)
	(f)	2	—	Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power, and SCS. See Exhibit 10(b)1 herein.

(14) Code of Ethics

Southern Company

	(a)		—	The Southern Company Code of Ethics. (Designated in Southern Company's Form 10-K for the year ended December 31, 2009, File No. 1-3526, as Exhibit 14(a).)

Alabama Power		
(b)	—	The Southern Company Code of Ethics. See Exhibit 14(a) herein.
Georgia Power		
(c)	—	The Southern Company Code of Ethics. See Exhibit 14(a) herein.
Gulf Power		
(d)	—	The Southern Company Code of Ethics. See Exhibit 14(a) herein.
Mississippi Power		
(e)	—	The Southern Company Code of Ethics. See Exhibit 14(a) herein.
Southern Power		
(f)	—	The Southern Company Code of Ethics. See Exhibit 14(a) herein.

(21)	Subsidiaries of Registrants				
	Southern Company				
	*	(a)		—	Subsidiaries of Registrant.
	Alabama Power				
		(b)		—	Subsidiaries of Registrant. See Exhibit 21(a) herein.
	Georgia Power				
		(c)		—	Subsidiaries of Registrant. See Exhibit 21(a) herein.
	Gulf Power				
		(d)		—	Subsidiaries of Registrant. See Exhibit 21(a) herein.
	Mississippi Power				
		(e)		—	Subsidiaries of Registrant. See Exhibit 21(a) herein.
	Southern Power				
		Omitted pursuant to General Instruction I(2)(b) of Form 10-K.			
(23)	Consents of Experts and Counsel				
	Southern Company				
	*	(a)	1	—	Consent of Deloitte & Touche LLP.
	Alabama Power				
	*	(b)	1	—	Consent of Deloitte & Touche LLP.
	Georgia Power				
	*	(c)	1	—	Consent of Deloitte & Touche LLP.
	Gulf Power				
	*	(d)	1	—	Consent of Deloitte & Touche LLP.
	Mississippi Power				
	*	(e)	1	—	Consent of Deloitte & Touche LLP.
	Southern Power				
	*	(f)	1	—	Consent of Deloitte & Touche LLP.
(24)	Powers of Attorney and Resolutions				
	Southern Company				
	*	(a)		—	Power of Attorney and resolution.
	Alabama Power				
	*	(b)		—	Power of Attorney and resolution.
	Georgia Power				
	*	(c)		—	Power of Attorney and resolution.
	Gulf Power				
	*	(d)		—	Power of Attorney and resolution.
	Mississippi Power				
	*	(e)		—	Power of Attorney and resolution.
	Southern Power				
	*	(f)		—	Power of Attorney and resolution.
(31)	Section 302 Certifications				
	Southern Company				
	*	(a)	1	—	Certificate of Southern Company's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
	*	(a)	2	—	Certificate of Southern Company's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
	Alabama Power				
	*	(b)	1	—	

Certificate of Alabama Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

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*	(b)	2	—	Certificate of Alabama Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
Georgia Power				
*	(c)	1	—	Certificate of Georgia Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
*	(c)	2	—	Certificate of Georgia Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
Gulf Power				
*	(d)	1	—	Certificate of Gulf Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
*	(d)	2	—	Certificate of Gulf Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
Mississippi Power				
*	(e)	1	—	Certificate of Mississippi Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
*	(e)	2	—	Certificate of Mississippi Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
Southern Power				
*	(f)	1	—	Certificate of Southern Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
*	(f)	2	—	Certificate of Southern Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

(32) Section 906 Certifications

Southern Company			
*	(a)	-	Certificate of Southern Company's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.
Alabama Power			
*	(b)	-	Certificate of Alabama Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.
Georgia Power			
*	(c)	-	Certificate of Georgia Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.
Gulf Power			
*	(d)	-	Certificate of Gulf Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.
Mississippi Power			
*	(e)	-	Certificate of Mississippi Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.
Southern Power			
*	(f)	-	Certificate of Southern Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

(101) XBRL-Related Documents

*	INS	-	XBRL Instance Document
*	SCH	-	XBRL Taxonomy Extension Schema Document
*	CAL	-	XBRL Taxonomy Calculation Linkbase Document
*	DEF	-	XBRL Definition Linkbase Document
*	LAB	-	XBRL Taxonomy Label Linkbase Document

*	PRE	-	XBRL Taxonomy Presentation Linkbase Document

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