SOUTHERN CO
Form DEF 14A
April 11, 2014
UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
SCHEDULE 14A
Proxy Statement Pursuant to Section 14(a) of the
Securities Exchange Act of 1934
Filed by the Registrant x
Filed by a Party other than the Registrant ¬
Check the appropriate box:

¬ Preliminary Proxy Statement
¬ Confidential, for Use of the Commission Only (as permitted by Rule 14a-6(e) (2))
x Definitive Proxy Statement
¬ Definitive Additional Materials
¬ Soliciting Materials Pursuant to §240.14a-12

THE SOUTHERN COMPANY

(Name of Registrant as Specified In Its Charter)
N/A

(Name of Person(s) Filing Proxy Statement, if other than Registrant)
Payment of Filing Fee (Check the appropriate box):

x No fee required.
¬ Fee computed on table below per Exchange Act Rules 14a-6(i) (1) and 0-11.
1) Title of each class of securities to which transaction applies:
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¬ Fee paid previously with preliminary materials.
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1) Amount Previously Paid:
2) Form, Schedule or Registration Statement No.:
3) Filing Party:
4) Date Filed:

Letter to Stockholders

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

Dear Fellow Stockholder:

You are invited to attend the 2014 Annual Meeting of Stockholders at 10 a.m. ET on Wednesday, May 28, 2014, at The Lodge Conference Center at Callaway Gardens, Pine Mountain, Georgia.

Your vote is important. Whether or not you plan to attend the meeting, please review the proxy material and vote by internet, phone, or mail as soon as possible.

At the annual meeting, I will report on our accomplishments from 2013, as well as our plans for 2014 and beyond. We will also elect our Board of Directors and vote on the other matters set forth in this Proxy Statement.

Throughout the entire history of Southern Company — 102 years and counting — we have been defined by a single unifying characteristic: Our relentless focus on the customer. Every action we take, every decision we make, is arrived at by asking one simple question: How does it benefit the families, businesses, and communities we serve?

This approach — more than any other component — has been the foundation of our success. Even during those times when our business faces issues and uncertainties, our customer-first philosophy enables us to succeed at what we do.

This Proxy Statement includes Appendix B, the 2013 Annual Report with Southern Company's audited financial statements and management's discussion and analysis of results of operation and financial condition.

We look forward to seeing you on May 28th. Thank you for your continued support of Southern Company.

/s/ Thomas A. Fanning
Thomas A. Fanning

Notice of Annual Meeting of Stockholders of The Southern Company

DATE:	Wednesday, May 28, 2014
TIME:	10:00 a.m., ET
PLACE:	The Lodge Conference Center at Callaway Gardens Highway 18 Pine Mountain, Georgia 31822
DIRECTIONS:	From Atlanta, Georgia — Take I-85 south to I-185 (Exit 21). From I-185 south, take Exit 34, Georgia Highway 18. Take Georgia Highway 18 east to Callaway. From Birmingham, Alabama — Take U.S. Highway 280 east to Opelika. Take I-85 north to Georgia Highway 18 (Exit 2). Take Georgia Highway 18 east to Callaway.

Items of Business

1. To elect 13 directors;
2. To ratify the appointment of Deloitte & Touche LLP as The Southern Company’s independent registered public accounting firm for 2014;
3. To approve on a non-binding advisory basis The Southern Company’s named executive officers' compensation;
4. To consider a stockholder proposal on an independent board chair, if properly presented at the meeting; and
5. To transact any other business properly coming before the meeting or any adjournments thereof.

Record Date

Stockholders of record at the close of business on March 31, 2014 are entitled to attend and vote at the meeting.

Annual Report to Stockholders

Appendix B to this Proxy Statement is The Southern Company's 2013 Annual Report.
By Order of the Board of Directors, Melissa K. Caen, Corporate Secretary, April 11, 2014

Voting Information

Even if you plan to attend the meeting in person, please provide your voting instructions as soon as possible by internet, by phone using the toll-free number, or by mail by marking, signing, dating, and returning the proxy form in the enclosed, postage-paid envelope.

Voting by the internet or by phone is fast and convenient,
and your vote is immediately confirmed and tabulated.

PROXY VOTING OPTIONS

YOUR VOTE IS IMPORTANT!

Voting early will ensure the presence of a quorum at the meeting and will save The Southern Company the expense and extra work of additional solicitation.

VOTE BY INTERNET
www.proxyvote.com
24 hours a day/7 days a week
Instructions:
Read this Proxy Statement
Go to the following website:
www.proxyvote.com
Have your proxy form or voting instruction form in hand and follow the instructions.

VOTE BY PHONE
1-800-690-6903
Toll-free 24 hours a day/7 days a week
Instructions:
Read this Proxy Statement
Have your proxy form or voting instruction form in hand and follow the instructions.

Please do not return the enclosed paper ballot if you are voting by internet or phone.

Proxy Statement

Frequently Asked Questions

Q: When will the Proxy Statement be mailed?

A: The Proxy Statement will be mailed on or about April 11, 2014.

Q: Who is entitled to vote?

A: All stockholders of record at the close of business on the record date of March 31, 2014 may vote. On that date, there were 891,480,510 shares of The Southern Company (Southern Company or the Company) common stock (Common Stock) outstanding and entitled to vote.

Q: How do I give voting instructions?

A: You may attend the meeting and give instructions in person or give instructions by internet, by phone, or by mail. Information for giving instructions is on the form of proxy and trustee voting instruction form (proxy form). For those investors whose shares are held by a broker, bank, or other nominee, you must complete and return the voting instruction form provided by your broker, bank, or nominee in order to instruct your broker, bank, or nominee on how to vote. The Proxies, named on the enclosed proxy form, will vote all properly executed proxies that are delivered pursuant to this solicitation and not subsequently revoked in accordance with the instructions given by you.

Q: Why is my vote important?

A: It is the right of every investor to vote on certain matters that affect the Company.

Q: Can I change my vote?

A: Yes. If you are a holder of record, you may revoke your proxy by submitting a subsequent proxy, or by written request received by the Company's Corporate Secretary prior to the meeting, or by attending the meeting and voting your shares. If your shares are held through a broker, bank, or other nominee, you must follow the instructions of your broker, bank, or other nominee to revoke your voting instructions.

Q: How are votes counted?

A: Each share counts as one vote. A quorum is required to transact business at the 2014 Annual Meeting of Stockholders (2014 Annual Meeting). Stockholders of record holding shares of stock constituting a majority of the shares entitled to be cast shall constitute a quorum. Abstentions that are marked on the proxy form and broker non-votes are included for the purpose of determining a quorum, but shares that otherwise are not voted are not counted toward a quorum. Neither abstentions, broker non-votes, nor shares that otherwise are not voted are counted for or against each of the matters being considered at the 2014 Annual Meeting and thus will not affect the outcome of the vote for these items.

Q: What are broker non-votes?

A: Broker non-votes occur on a matter up for vote when a broker, bank, or other holder of shares you own in "street name" is not permitted to vote on that particular matter without instructions from you, you do not give such instructions, and the broker, bank, or other nominee indicates on its proxy form, or otherwise notifies the Company, that it does not have authority to vote its shares on that matter. Whether a broker has authority to vote its shares on uninstructed matters is determined by New York Stock Exchange (NYSE) rules.

Q: What does it mean if I get more than one proxy form?

A: You will receive a proxy form for each account that you have. Please vote proxies for all accounts to ensure that all of your shares are voted. If you wish to consolidate multiple registered accounts, please contact Shareholder Services at Computershare Inc. at (800) 554-7626.

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Q: Can the Proxy Statement be accessed from the internet?

A: Yes. You can access the Company's website at http://investor.southerncompany.com/proxy.cfm to view the 2014 Proxy Statement.

Q: How do I attend the 2014 Annual Meeting in person?

A: All attendees need to bring photo identification, such as a driver's license, to gain admission to the 2014 Annual Meeting. If you are a holder of record, the top half of your proxy card is your admission ticket. If you hold your shares in street name, you will need proof of ownership to be admitted to the meeting. Examples of proof of ownership are a recent brokerage statement or a letter from your bank or broker. If you want to vote your shares held in street name, you must get a legal proxy in your name from the broker, bank, or other nominee that holds your shares. Please note that cameras, sound or video recording equipment, cellular telephones, smartphones or other similar equipment, and electronic devices are not permitted to be used during the 2014 Annual Meeting.

Q: Does the Company offer electronic delivery of proxy materials?

A: Yes. Most stockholders can elect to receive an email that will provide an electronic link to the Proxy Statement, which includes the 2013 Annual Report as an appendix. Opting to receive your proxy materials on-line will save the Company the cost of producing and mailing documents and also will give you an electronic link to the proxy voting site.

You may sign up for electronic delivery when you vote your proxy via the internet or by visiting www.icsdelivery.com/so.

Once you enroll for electronic delivery, you will receive proxy materials electronically as long as your account remains active or until you cancel your enrollment. If you consent to electronic access, you will be responsible for your usual internet-related charges (e.g., on-line fees and telephone charges) in connection with electronic viewing and printing of the Proxy Statement, which includes the 2013 Annual Report as an appendix. The Company will continue to distribute printed materials to stockholders who do not consent to access these materials electronically.

Q: What is “householding?”

A: Stockholders sharing a single address may receive only one copy of the Proxy Statement, which includes the 2013 Annual Report as an appendix, unless the transfer agent, broker, bank, or other nominee has received contrary instructions from any owner at that address. This practice — known as householding — is designed to reduce printing and mailing costs. If a stockholder of record would like to either participate or cancel participation in householding, he or she may contact Shareowner Services at (800) 554-7626 or by mail at The Southern Company, c/o Computershare, P.O. Box 30170, College Station, TX 77842-3170. If you own indirectly through a broker, bank, or other nominee, please contact your financial institution.

Q: What is the Board’s recommendation for the proposals?

A: The Board of Directors recommends votes "FOR" each of Item Nos. 1, 2 and 3 and a vote "AGAINST" Item No. 4 in this Proxy Statement.

Q: How many votes are needed to approve each of the items of business?

A: The affirmative vote of a majority of the votes cast is required for approval of each of the items presented in this Proxy Statement.

Q: When are stockholder proposals due for the 2015 Annual Meeting of Stockholders?

A: The deadline for the receipt of stockholder proposals to be considered for inclusion in the Company's proxy materials for the 2015 Annual Meeting of Stockholders is December 12, 2014. Proposals must be submitted in writing to Melissa K. Caen, Corporate Secretary, Southern Company, 30 Ivan Allen Jr. Boulevard NW, Atlanta, Georgia 30308. Additionally, the proxy solicited by the Board of Directors for next year's meeting will confer discretionary authority to vote on any stockholder proposal presented at that meeting that is not included in the Company's proxy materials unless the Company is provided written notice of such proposal no later than February 25, 2015.

Q: Who is soliciting these proxies and who pays the expense of such solicitations?

A: These proxies are being solicited on behalf of the Company's Board of Directors. The Company pays the cost of soliciting proxies. The Company has retained Alliance Advisors LLC to assist with the solicitation of proxies for a fee of $8,500, plus reimbursement of out-of-pocket expenses and any agreed upon charges up to $70,000 associated with additional solicitation. The officers or other employees of the Company or its subsidiaries may solicit proxies to have a larger representation at the meeting. None of these officers or other employees of the Company will receive any additional compensation for these services. Upon request, the Company will reimburse brokerage houses and other custodians, nominees, and fiduciaries for their reasonable out-of-pocket expenses for forwarding solicitation material to the beneficial owners of the Company's common stock.

Important Notice Regarding the Availability of Proxy Materials for the 2014 Annual Meeting to be held on May 28, 2014:

The Company's 2014 Proxy Statement, which includes the 2013 Annual Report as an appendix, is also available free of charge on the Company's website at http://investor.southerncompany.com/proxy.cfm.

The Company's 2013 Annual Report to the Securities and Exchange Commission (SEC) on Form 10-K will be provided without charge upon written request to Melissa K. Caen, Corporate Secretary, Southern Company, 30 Ivan Allen Jr. Boulevard NW, Atlanta, Georgia 30308.

COMPANY ORGANIZATION

Southern Company is a holding company managed by a core group of officers and governed by a Board of Directors that is currently comprised of 14 members.

At the 2014 Annual Meeting, stockholders will elect 13 Directors. The nominees for election as Directors consist of 12 non-employees and one executive officer of the Company.

The Board of Directors has adopted and operates under a set of Corporate Governance Guidelines which are available on the Company's website at www.southerncompany.com under Information for Investors/Corporate Governance.

CORPORATE GOVERNANCE WEBSITE

In addition to the Company's Corporate Governance Guidelines (which include Board independence criteria), other information relating to corporate governance of the Company is available on the Company's Corporate Governance webpage at www.southerncompany.com under Information for Investors/Corporate Governance or directly at http://investor.southerncompany.com/governance.cfm, including:

- Code of Ethics
- By-Laws of the Company
- Executive Stock Ownership Requirements
- Board Committee Charters
- Board of Directors — Background and Experience
- Management Council — Background and Experience
- Composition of Board Committees
- SEC filings
- Link for on-line communication with Board of Directors
- Political Spending and Lobbying-Related Activities
- Anti-Hedging Provision

The Corporate Governance documents also may be obtained by requesting a copy from Melissa K. Caen, Corporate Secretary, Southern Company, 30 Ivan Allen Jr. Boulevard NW, Atlanta, Georgia 30308.

DIRECTOR INDEPENDENCE

No Director will be deemed to be independent unless the Board of Directors affirmatively determines that the Director has no material relationship with the Company directly or as an officer, stockholder, or partner of an organization that has a relationship with the Company. The Board of Directors has adopted categorical guidelines which provide that a Director will not be deemed to be independent if within the preceding three years:

- The Director was employed by the Company or the Director's immediate family member was an executive officer of the Company.
- The Director has received, or the Director's immediate family member has received, during any 12-month period, direct compensation from the Company of more than $120,000, other than Director and committee fees. (Compensation received by an immediate family member for service as a non-executive employee of the Company need not be considered.)
- The Director was affiliated with or employed by, or the Director's immediate family member was affiliated with or employed in a professional capacity by, a present or former external auditor of the Company and personally worked on the Company's audit.

- The Director was employed, or the Director's immediate family member was employed, as an executive officer of a company where any member of the Company's present executive officers at the same time served on that company's compensation committee.
- The Director is a current employee, or the Director's immediate family member is a current executive officer, of a company that has made payments to, or received payments from, the Company for property or services in an amount which, in any of the last three fiscal years, exceeds the greater of $1,000,000 or two percent of that company's consolidated gross revenues.

Additionally, a Director will not be deemed to be independent if the Director or the Director's spouse serves as an executive officer of a charitable organization to which the Company made discretionary contributions exceeding the greater of $1,000,000 or two percent of the organization's total annual charitable receipts.

At least annually, the Board receives a report on all commercial, consulting, legal, accounting, charitable, or other business relationships that a Director or the Director's immediate family members have with the Company. This report specifically includes all ordinary course transactions with entities with which the Directors are associated. The Board determined that the Company and its subsidiaries followed the Company's procurement policies and procedures, that the amounts reported were well under the thresholds contained in the Director independence requirements, and that no Director had a direct or indirect material interest in the transactions. See Other Information - Certain Relationships and Related Transactions for a discussion of related party transactions identified by the Company.

The Board reviewed all contributions made by the Company and its subsidiaries to charitable organizations with which the Directors are associated. The Board determined that the contributions were consistent with other contributions by the Company and its subsidiaries to charitable organizations and none were approved outside the Company's normal procedures.

At least annually, the Board also reviews Director independence. The Board considers transactions, if any, identified in the review of the report discussed above that affect Director independence, including any transactions in which the amounts reported were above the threshold contained in the Director independence requirements and in which a Director had a direct or indirect material interest. No such transactions were identified and, as a result, no such transactions were considered by the Board. In determining independence, the Board also considered that, in the ordinary course of the Southern Company system's business, electricity is provided to some Directors and entities with which the Directors are associated on the same terms and conditions as provided to other customers of the Southern Company system.

As a result of its review of Director independence, the Board affirmatively determined that none of the following persons who are currently serving as Directors or who served during 2013 or who are nominees for election as Directors has a material relationship with the Company and, as a result, such persons are determined to be independent: Juanita Powell Baranco, Jon A. Boscia, Henry A. Clark III, David J. Grain, H. William Habermeyer, Jr., Veronica M. Hagen, Warren A. Hood, Jr., Linda P. Hudson, Donald M. James, Dale E. Klein, William G. Smith, Jr., Steven R. Specker, and E. Jenner Wood III. Thomas A. Fanning, a current Director, is Chairman of the Board, President, and Chief Executive Officer of the Company and is not independent.

COMMUNICATING WITH THE BOARD

Interested parties may communicate directly with the Company's Board or specified Directors, including the Presiding Director. Communications may be sent to the Company's Board or to specified Directors, including the Presiding Director, by regular mail or electronic mail. Regular mail should be sent to the attention of Melissa K. Caen, Corporate Secretary, Southern Company, 30 Ivan Allen Jr. Boulevard NW, Atlanta, Georgia 30308. The electronic mail address is CORPGOV@southerncompany.com. The electronic mail address also can be accessed from the Corporate Governance webpage located under Information for Investors/Corporate Governance on the Company's website at www.southerncompany.com, under the link entitled Governance Inquiries. With the exception of commercial solicitations, all communications directed to the Board or to specified Directors will be relayed to them.

DIRECTOR COMPENSATION

Only non-employee Directors of the Company are compensated for service on the Board of Directors. During 2013, the pay components for non-employee Directors were:

Annual retainers:

- $100,000 cash retainer
- Additional $12,500 cash retainer if serving as a chair of a committee of the Board
- Additional $12,500 cash retainer if serving as the Presiding Director of the Board

Annual equity grant:

- $105,000 in deferred Common Stock units until Board membership ends

Meeting fees:

- Meeting fees are not paid for participation in the initial eight meetings of the Board in a calendar year. If more than eight meetings of the Board are held in a calendar year, $2,500 will be paid for participation in each meeting of the Board beginning with the ninth meeting.
- Meeting fees are not paid for participation in a meeting of a committee of the Board.

In accordance with the Company's Corporate Governance Guidelines and the Governance Committee's Charter, the Governance Committee periodically reviews the level and form of Director compensation and recommends any changes to the Board for approval to assure that the level of compensation is reasonable and competitive for an entity of the Company's size and scope. In 2013, the Governance Committee engaged an independent consultant, Frederic W. Cook & Co., to assist in an evaluation of non-employee Director compensation. As a result of the evaluation, the Board approved increases in certain components of non-employee Director compensation. Effective January 1, 2014, the pay components for non-employee Directors are:

Annual retainers:

- $100,000 cash retainer
- Additional $20,000 cash retainer if serving as a chair of a committee of the Board
- Additional $20,000 cash retainer if serving as the Presiding Director of the Board

Annual equity grant:

- $120,000 in deferred Common Stock units until Board membership ends

Meeting fees:

- Meeting fees are not paid for participation in the initial eight meetings of the Board in a calendar year. If more than eight meetings of the Board are held in a calendar year, $2,500 will be paid for participation in each meeting of the Board beginning with the ninth meeting.
- Meeting fees are not paid for participation in a meeting of a committee of the Board.

DIRECTOR DEFERRED COMPENSATION PLAN

The annual equity grant is required to be deferred in shares of Common Stock under the Deferred Compensation Plan for Outside Directors of The Southern Company, as amended and restated effective January 1, 2008 (Director Deferred Compensation Plan), and 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 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. Such 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 the prime interest rate which is paid in cash upon leaving the Board.

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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. The Company has established a grantor trust that primarily holds Common Stock that funds the Common Stock units that are distributed in shares of Common Stock. Directors have voting rights in the shares held in the trust attributable to these units.

DIRECTOR COMPENSATION TABLE

The following table reports all compensation to the Company's non-employee Directors during 2013, including amounts deferred in the Director Deferred Compensation Plan. Non-employee Directors do not receive Non-Equity Incentive Plan Compensation or stock option awards, and there is no pension plan for non-employee Directors. Ms. Linda P. Hudson, who was elected to the Board effective March 1, 2014, is not included in this table.

Name	Fees Earned or Paid in Cash ($) (1)	Stock Awards ($) (2)	Non-Equity Incentive Plan Compensation ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)	All Other Compensation ($) (3)	Total ($)
Juanita Powell Baranco	115,000	105,000	—	—	1,025	221,025
Jon A. Boscia	115,000	105,000	—	—	920	220,920
Henry A. Clark III	112,500	105,000	—	—	1,065	218,565
David J. Grain	102,500	105,000	—	—	810	208,310
H. William Habermeyer, Jr.	112,500	105,000	—	—	810	218,310
Veronica M. Hagen	115,000	105,000	—	—	1,099	221,099
Warren A. Hood, Jr.	100,000	105,000	—	—	879	205,879
Donald M. James	102,500	105,000	—	—	995	208,495
Dale E. Klein	100,000	105,000	—	—	810	205,810
William G. Smith, Jr.	115,000	105,000	—	—	810	220,810
Steven R. Specker	102,500	105,000	—	—	999	208,499
E. Jenner Wood III	102,500	105,000	—	—	1,025	208,525

(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) Consists of reimbursements for taxes on imputed income associated with gifts and activities provided to attendees at Company-sponsored events.

DIRECTOR STOCK OWNERSHIP GUIDELINES

Under the Company's Corporate Governance Guidelines, non-employee Directors are required to beneficially own, within five years of their initial election to the Board, Common Stock equal to at least five times the annual Director cash retainer fee. Also, as described in the Director Compensation section above, the annual equity grant received as a part of the annual compensation for non-employee Directors is required to be deferred until Board membership ends. All non-employee Directors either meet the stock ownership guideline or are expected to meet the guideline within the allowed timeframe.

BOARD LEADERSHIP STRUCTURE

The Board believes that its current leadership structure, which has a combined role of Chief Executive Officer and Chairman counterbalanced by a strong independent Board led by a Presiding Director, is most suitable for the

Company at this time. The combined role of Chief Executive Officer and Chairman is held by Mr. Fanning who is the Director most familiar with the Company's business and industry, including the regulatory structure and other industry-specific matters, as well as being most capable of effectively identifying strategic priorities and leading discussion and execution of strategy. Independent Directors and management have different perspectives and roles in strategy development. The Chief Executive Officer brings Company-specific experience and expertise, while the Company's independent Directors bring experience, oversight, and expertise from outside the Company and its industry. The Board believes that the combined role of Chief Executive Officer and Chairman promotes the development and execution of the Company's strategy and facilitates the flow of information between management and the Board, which is essential to effective corporate governance. The Board believes the combined role of Chief Executive Officer and Chairman, together with a strong independent Presiding Director having the duties described below, is in the best interest of stockholders because it provides the optimal balance between independent oversight of management and unified leadership.

PRESIDING DIRECTOR

Mr. William G. Smith, Jr. was appointed to serve as the Presiding Director effective May 23, 2012 until May 28, 2014. In February 2014, Ms. Veronica M. Hagen was appointed to serve as the Presiding Director effective May 28, 2014 until the Company's 2016 Annual Meeting of Stockholders. The Presiding Director is selected bi-annually by and from the independent Directors. Non-management Directors meet, without management, on each regularly-scheduled Board meeting date, and at other times as deemed appropriate by the Presiding Director or two or more other independent Directors. The Presiding Director is responsible for chairing executive sessions and acting as the principal liaison between the Chairman and the non-management Directors. However, each Director is afforded direct and complete access to the Chairman at any time as such Director deems necessary or appropriate. The Presiding Director meets regularly with the Chairman and also serves as the primary contact Director for stockholders and other interested parties. The Presiding Director is also involved in communicating any sensitive issues to the Directors and chairing Board meetings in the absence of the Chairman.

MEETINGS OF NON-MANAGEMENT DIRECTORS

Non-management Directors meet in executive session without any members of the Company's management present on each regularly-scheduled Board meeting date. These executive sessions promote an open discussion of matters in a manner that is independent of the Chairman and Chief Executive Officer. The Presiding Director chairs each of these executive sessions.

COMMITTEES OF THE BOARD

Committee Charters

Charters for each of the five standing committees can be found at the Company's website — www.southerncompany.com under Information for Investors/Corporate Governance.

Audit Committee:

- Current members are Mr. Boscia (Chair), Mr. Grain, Mr. Hood, and Ms. Hudson (1)
- Met 10 times in 2013
- The Audit Committee's duties and responsibilities, which are described in its charter, include the following:
- Oversee the Company's financial reporting, audit processes, internal controls, and legal, regulatory, and ethical compliance.
- Appoint the Company's independent registered public accounting firm, approve its services and fees, and establish and review the scope and timing of its audits.
- Review and discuss the Company's financial statements with management, the internal auditors, and the independent registered public accounting firm, including critical accounting policies and practices, material alternative financial treatments within generally accepted accounting principles, proposed adjustments, control recommendations, significant management judgments and accounting estimates, new accounting policies, changes in accounting principles, any disagreements with management, and other material written communications between the internal auditors and/or the independent registered public accounting firm and management.
- Recommend the filing of the Company's and its registrant subsidiaries' annual financial statements with the SEC.

The Board has determined that the members of the Audit Committee are independent as defined by the NYSE corporate governance rules within its listing standards and rules of the SEC promulgated pursuant to the Sarbanes-Oxley Act of 2002. The Board has determined that Mr. Boscia qualifies as an "audit committee financial expert" as defined by the SEC.

(1) Ms. Hudson was appointed a member of the Audit Committee effective March 1, 2014.

Compensation and Management Succession Committee (Compensation Committee):

- Current members are Ms. Hagen (Chair), Mr. Clark, Mr. Habermeyer, and Mr. Smith
- Met nine times in 2013
- The Compensation Committee's duties and responsibilities, which are described in its charter, include the following:
- Evaluate performance of executive officers and establish their compensation, administer executive compensation plans, and review management succession plans.
- Annually review a tally sheet of all components of the executive officers' compensation and take actions required of it under the Pension Plan for employees of the Company's subsidiaries.

The Board has determined that each member of the Compensation Committee is independent.

Governance

During 2013, the Compensation Committee's governance practices included:

- Considering compensation for the named executive officers in the context of all of the components of total compensation;
- Considering annual adjustments to pay over the course of two meetings and requiring more than one meeting to make other important decisions;
- Receiving meeting materials several days in advance of meetings;
- Having regular executive sessions of Compensation Committee members only;
- Having direct access to independent compensation consultants;
- Conducting a performance/payout analysis versus peer companies for the performance-based compensation program to provide a check on the Company's goal-setting process; and
- Reviewing a compensation risk assessment through a process developed by its independent compensation consultant.

Role of Executive Officers

The Chief Executive Officer, with input from the Company's Human Resources staff, recommends to the Compensation Committee: base salary, target performance-based compensation levels, actual performance-based compensation payouts, and long-term performance-based grants for the Company's executive officers (other than the Chief Executive Officer). The Compensation Committee considers, discusses, modifies as appropriate, and takes action on such recommendations.

Role of Compensation Consultant

The Compensation Committee, which has authority to retain independent advisors, including compensation consultants, at the Company's expense, engaged Pay Governance LLC (Pay Governance) to provide an independent assessment of the current executive compensation program and any management-recommended changes to that program and to work with Company management to ensure that the executive compensation program is designed and administered consistent with the Compensation Committee's requirements. The Compensation Committee also expected Pay Governance to advise on executive compensation and related corporate governance trends.

Pay Governance is engaged solely by the Compensation Committee and does not provide any services directly to management unless authorized to do so by the Compensation Committee. In connection with its engagement of Pay Governance, the Compensation Committee reviewed Pay Governance's independence including (1) the amount of fees received by Pay Governance from the Company as a percentage of Pay Governance's total revenue; (2) its policies and procedures designed to prevent conflicts of interest; and (3) the existence of any business or personal relationships, including Common Stock ownership, that could impact independence. After reviewing these and other factors, the Compensation Committee determined that Pay Governance is independent and the engagement did not present any conflicts of interest. Pay Governance also determined that it was independent from management, which was confirmed in a written statement delivered to the Compensation Committee.

During 2013, Pay Governance assisted the Compensation Committee with analyzing comprehensive market data and its implications for pay at the Company and its affiliates and various other governance, design, and compliance matters.

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Finance Committee:

- Current members are Mr. Clark (Chair), Mr. James, and Mr. Smith
- Met seven times in 2013
- The Finance Committee's duties and responsibilities, which are described in its charter, include the following:
- Review the Company's financial matters and recommend actions such as dividend philosophy and financial plan approval to the Board.
- Provide input to the Compensation Committee regarding the Company's financial plan and associated financial goals.

The Board has determined that each member of the Finance Committee is independent.

Governance Committee:

- Current members are Ms. Baranco (Chair), Mr. James, Dr. Klein, Dr. Specker, and Mr. Wood
- Met six times in 2013
- The Governance Committee's duties and responsibilities, which are described in its charter, include the following:
- Review Board size, composition, and membership criteria and identify and recommend Director candidates.
- Oversee and make recommendations regarding the composition of the Board and its committees.
- Review and make recommendations regarding total compensation for non-employee Directors.
- Periodically review and recommend updates to the Corporate Governance Guidelines and Board committee charters.
- Coordinate the performance evaluations of the Board and its committees.
- Review stock ownership of non-employee Directors annually to ensure compliance with the Company's Director stock ownership guidelines.

The Board has determined that each member of the Governance Committee is independent.

Nominees for Election to the Board

The Governance Committee, comprised entirely of independent Directors, is responsible for identifying, evaluating, and recommending nominees for election to the Board. The Governance Committee solicits recommendations for candidates for consideration from its current Directors and is authorized to engage third-party advisers to assist in the identification and evaluation of candidates for consideration. Any stockholder may make recommendations to the Governance Committee by sending a written statement setting forth the candidate's qualifications, relevant biographical information, and signed consent to serve. These materials should be submitted in writing to the Company's Corporate Secretary and received by that office by December 12, 2014 for consideration by the Governance Committee as a nominee for election at the Annual Meeting of Stockholders to be held in 2015. Any stockholder recommendation is reviewed in the same manner as candidates identified by the Governance Committee or recommended to the Governance Committee.

While the Company's Corporate Governance Guidelines do not prescribe diversity standards, such Guidelines mandate that the Board as a whole should be diverse. At least annually, the Governance Committee evaluates the expertise and needs of the Board to determine the proper membership and size. As part of this evaluation, the Governance Committee considers aspects of diversity, such as diversity of age, race, gender, education, industry, business background, and civic service, in the selection of candidates to serve on the Board. The Governance Committee only considers candidates with the highest degree of integrity and ethical standards. The Governance Committee evaluates a candidate's independence from management, ability to provide sound and informed judgment, history of achievement reflecting superior standards, willingness to commit sufficient time, financial literacy, number of other board memberships, genuine interest in the Company and a recognition that, as a member of the Board, one is accountable to the stockholders of the Company, not to any particular interest group. The Board as a whole should also have collective knowledge and experience in accounting, finance, leadership, business operations, risk management, corporate governance, and the Company's industry. The Governance Committee recommends candidates to the Board for consideration as nominees. Final selection of the nominees is within the sole discretion of the Board.

Ms. Linda P. Hudson was recommended by the Governance Committee for election to the Board and was elected as a Director effective March 1, 2014. Ms. Hudson was identified jointly by members of the Board and management.

Nuclear/Operations Committee:

- Current members are Mr. Habermeyer (Chair), Ms. Baranco, Ms. Hagen, Dr. Klein, Dr. Specker, and Mr. Wood
- Met six times in 2013
- The Nuclear/Operations Committee's duties and responsibilities, which are described in its charter, include the following:
  - Oversee information, activities, and events relative to significant operations of the Southern Company system including nuclear and other power generation facilities, transmission and distribution, fuel, and information technology initiatives.
  - Oversee the Southern Company system's management of significant construction projects.
  - Provide input to the Compensation Committee on the Southern Company system's key operational goals and metrics.

The Board has determined that each member of the Nuclear/Operations Committee is independent.

BOARD RISK OVERSIGHT

The Board and its committees have both general and specific risk oversight responsibilities. The Board has broad responsibility to provide oversight of significant risks to the Company primarily through direct engagement with Company management and through delegation of ongoing risk oversight responsibilities to the committees. The charters of the committees as approved by the Board and the committees' checklists of agenda items define the areas of risk for which each committee is responsible for providing ongoing oversight.

Each committee annually provides ongoing oversight for each of the Company's most significant risks designated to it as described in its charter or otherwise assigned by the Board, reports to the Board on their oversight activities, and elevates review of risk issues to the Board as appropriate.

For each committee, the Chief Executive Officer of the Company has designated a member of management as the primary responsible officer for providing information and updates related to the significant risks. These officers ensure that all significant risks identified on the Company's risk profile are reviewed with the Board and/or the appropriate committee(s) at least annually.

In addition to oversight of its designated risks, the Audit Committee is also responsible for reviewing the adequacy of the risk oversight process and for reviewing documentation that appropriate risk management and oversight are occurring. In order to fulfill this duty, a report is made to the Audit Committee at least annually. This report documents which significant risk reviews have occurred and the committee(s) reviewing such risks. In addition, an overview is provided at least annually of the risk assessment and profile process conducted by Company management.

At least annually, the Board and the Audit Committee review the Company's risk profile to ensure that oversight of each risk is properly designated to an appropriate committee or the full Board. Additionally, the Audit Committee receives regular updates from Internal Auditing, as needed, and quarterly updates as part of the disclosure controls process.

The Company believes that its leadership structure supports the risk oversight function of the Board. While the Company has a combined role of Chairman and Chief Executive Officer, an independent Director chairs each committee responsible for providing ongoing oversight of certain areas of risk. Also, there is open communication between the Company's management and the Directors and all Directors are actively involved in the risk oversight function.

DIRECTOR ATTENDANCE

The Board of Directors met nine times in 2013. Average Director attendance at all applicable Board and committee meetings was 97%. No nominee attended less than 75% of applicable meetings.

All Director nominees are expected to attend the Annual Meeting of Stockholders. All the members of the Board of Directors serving on May 23, 2013, the date of the 2013 Annual Meeting of Stockholders, attended the meeting.

RETIRING DIRECTOR

Mr. H. William Habermeyer, Jr., who has served as a Director of the Company since 2007, is retiring from the Board effective May 27, 2014. During his time on the Board, Mr. Habermeyer has chaired the Nuclear/Operations Committee and has been a member of the Compensation Committee and the Finance Committee. Mr. Habermeyer retired in 2006 from his position as President and Chief Executive Officer of Progress Energy Florida, Inc., which was a subsidiary of Progress Energy Inc., a diversified energy company. Mr. Habermeyer is a retired Rear Admiral who served in the United States Navy for 28 years. Mr. Habermeyer is currently a Director of Raymond James Financial Inc., where he serves on the Audit Committee. He served on the Board of USEC Inc., a global energy company, from 2008 until 2013. Mr. Habermeyer has a wealth of experience in utility business operations, with a focus on nuclear matters, which have been valuable to the Board.

Stock Ownership Table

STOCK OWNERSHIP OF DIRECTORS, NOMINEES, AND EXECUTIVE OFFICERS

The following table shows the number of shares of Common Stock beneficially owned by Directors, nominees, and executive officers as of February 28, 2014. The shares owned by all Directors, nominees, and executive officers as a group constitute less than one percent of the total number of shares of Common Stock outstanding.

Directors, Nominees, and Executive Officers	Shares Beneficially Owned (1)	Shares Beneficially Owned Include: Deferred Common Stock Units (2)	Shares Individuals Have Rights to Acquire within 60 days (3)	Shares Held by Family Member(4)
Juanita Powell Baranco	49,885	49,256	—	—
Art P. Beattie	374,139	—	360,375	127
Jon A. Boscia	76,863	17,863	—	—
W. Paul Bowers	1,040,935	—	982,863	—
Henry A. Clark III	11,819	11,819	—	—
Thomas A. Fanning	1,723,999	—	1,685,514	—
David J. Grain	14,438	3,938	—	—
Kimberly S. Greene	109,705	—	109,705	—
H. William Habermeyer, Jr.	19,847	19,847	—	—
Veronica M. Hagen	29,332	29,332	—	—
Warren A. Hood, Jr.	39,756	39,125	—	—
Linda P. Hudson (5)	—	—	—	—
Donald M. James	88,244	88,244	—	—
Dale E. Klein	9,054	9,054	—	—
Charles D. McCrary	707,555	—	673,319	—
William G. Smith, Jr.	54,523	48,803	—	862
Steven R. Specker	8,335	8,335	—	—
E. Jenner Wood III	18,786	14,634	—	—
Directors, Nominees, and Executive Officers as a Group (23 people) (6)	6,056,248	340,250	5,414,190	989

(1) "Beneficial ownership" means the sole or shared power to vote, or to direct the voting of, a security, or investment power with respect to a security, or any combination thereof.

(2) Indicates the number of deferred Common Stock units held under the Director Deferred Compensation Plan. Shares indicated are included in the Shares Beneficially Owned column.

(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.

(4) Each Director disclaims any interest in shares held by family members. Shares indicated are included in the Shares Beneficially Owned column.

(5) Ms. Hudson was elected to the Board effective March 1, 2014.

(6) This list includes all executive officers serving as of February 28, 2014.

STOCK OWNERSHIP OF CERTAIN OTHER BENEFICIAL OWNERS

According to a Schedule 13G/A filed with the SEC on January 30, 2014 by Blackrock Inc. and a Schedule 13G filed with the SEC on February 11, 2014 by The Vanguard Group (collectively, the Ownership Reports), the following reported beneficial ownership of more than 5% of the outstanding shares of Common Stock:

Title of Class	Name and Address	Shares Beneficially Owned	Percentage of Class Owned
Common Stock	Blackrock Inc. 40 East 52nd Street New York, NY 10022	45,777,102	5.20
Common Stock	The Vanguard Group 100 Vanguard Blvd. Malvern, PA 19355	44,207,445	5.01

According to the Ownership Reports, Blackrock Inc. and The Vanguard Group each of which held all of their respective shares as a parent holding company or control person in accordance with Rule 13(d)-1(b)(1)(ii)(G). According to the Ownership Reports, both Blackrock Inc. and The Vanguard Group each have sole voting power and sole investment power over their respective shares.

ITEM NO. 1 — ELECTION OF DIRECTORS

Nominees for Election as Directors

The Proxies named on the proxy form will vote, unless otherwise instructed, each properly executed proxy form for the election of the following nominees as Directors. If any named nominee becomes unavailable for election, the Board may substitute another nominee. In that event, the proxy would be voted for the substitute nominee unless instructed otherwise on the proxy form. Each nominee, if elected, will serve until the 2015 Annual Meeting of Stockholders.

The Board of Directors, acting upon the recommendation of the Governance Committee, nominates the following individuals for election to the Southern Company Board of Directors. Each nominee holds or has held senior executive positions, maintains the highest degree of integrity and ethical standards, and complements the needs of the Company. Through their positions, responsibilities, skills, and perspectives, which span various industries and organizations, these nominees represent a Board that is diverse and possesses the collective knowledge and experience in accounting, finance, leadership, business operations, risk management, corporate governance, and the Company's industry, as detailed below.

Juanita Powell Baranco
Age: 65
Director since: 2006
Board committees: Governance (Chair), Nuclear/Operations
Principal occupation: Executive Vice President and Chief Operating Officer of Baranco Automotive Group, automobile sales
Other directorships: None (formerly a Director of Cox Radio, Inc. and Georgia Power Company)

Director qualifications: Ms. Baranco had a successful legal career, which included serving as Assistant Attorney General for the State of Georgia, before she and her husband founded the first Baranco dealership in Atlanta in 1978. She served as a Director on the Board of Georgia Power Company (Georgia Power), the largest subsidiary of the Company, from 1997 to 2006. During her tenure on the Georgia Power Board, she was a member of the Controls and Compliance, Diversity, Executive, and Nuclear Operations Overview Committees. She served on the Federal Reserve Bank of Atlanta Board for a number of years and also on the Boards of Directors of John H. Harland Company and Cox Radio, Inc. An active leader in the Atlanta community, she serves as Chair of the Board of Trustees for Clark Atlanta University and as a Director of the Catholic Foundation of North Georgia and the Commerce Club. She is also past Chair of the Board of Regents for the University System of Georgia and past Board Chair for the Sickle Cell Foundation of Georgia. The Board has benefited from Ms. Baranco's particular expertise in business operations and her civic involvement.

Jon A. Boscia
Age: 61

Director since: 2007

Board committee: Audit (Chair)
Principal occupation: Founder and President, Boardroom Advisors LLC, board governance consulting firm

Other directorships: PHH Corporation (formerly a Director of Sun Life Financial Inc., Armstrong World Industries, Lincoln Financial Group, Georgia Pacific Corporation, and The Hershey Company)

Director qualifications: From September 2008 until March 2011, Mr. Boscia served as President of Sun Life Financial Inc. In this capacity, Mr. Boscia managed a portfolio of the company's operations with ultimate responsibility for the United States, United Kingdom, and Asia business groups and directed the global marketing and investment management functions. Previously, Mr. Boscia served as Chairman of the Board and Chief Executive Officer of Lincoln Financial Group, a diversified financial services organization, until his retirement in 2007. Mr. Boscia became the Chief Executive Officer of Lincoln Financial Group in 1998. During his time at Lincoln Financial Group, the company earned a reputation for its stellar performance in making major acquisitions. Mr. Boscia is a past member of the Board of The Hershey Company, where he chaired the Corporate Governance Committee and served on the Executive Committee, and past member of the Board of Sun Life Financial Inc., where he was a member of the Investment Oversight Committee and the Risk Review Committee. He serves on the Board of PHH Corporation, where he is currently Chair of the Audit Committee and a member of the Regulatory Oversight Committee. Mr. Boscia will retire as a member of the Board of Directors of PHH Corporation on May 22, 2014. In addition, Mr. Boscia has served in leadership positions on other public company boards as well as not-for-profit and industry boards. His extensive background in finance, investment management, information technology, and corporate governance are valuable to the Board.

Henry A. "Hal" Clark III

Age: 64

Director since: 2009

Board committees: Finance (Chair), Compensation and Management Succession

Principal occupation: Senior Advisor of Evercore Partners Inc. (formerly Lexicon Partners, LLC), corporate finance advisory firm, since July 2009

Other directorships: None

Director qualifications: As a Senior Advisor with Evercore Partners Inc. (formerly Lexicon Partners, LLC), Mr. Clark is primarily focused on expanding advisory activities in North America with a particular focus on the power and utilities sectors. With more than 30 years of experience in the global financial and the utility industries, Mr. Clark brings a wealth of experience in finance and risk management to his role as a Director. Prior to joining Evercore Partners Inc., Mr. Clark was Group Chairman of Global Power and Utilities at Citigroup, Inc. from 2001 to 2009. His work experience includes numerous capital markets transactions of debt, equity, bank loans, convertible securities, and securitization, as well as advice in connection with mergers and acquisitions. He also has served as policy advisor to numerous clients on capital structure, cost of capital, dividend strategies, and various financing strategies. He has served as Chair of the Wall Street Advisory Group of the Edison Electric Institute.

Thomas A. Fanning

Age: 57

Director since: 2010

Principal occupation: Chairman of the Board, President, and Chief Executive Officer of the Company since December 2010

Other directorships: Federal Reserve Bank of Atlanta, Alabama Power Company, Georgia Power, and Southern Power Company

Director qualifications: Mr. Fanning had held numerous leadership positions across the Southern Company system during his more than 30 years with the Company. He served as Executive Vice President and Chief Operating Officer of the Company from 2008 to 2010, leading the Company's generation and transmission, engineering, and construction services, research and environmental affairs, system planning, and competitive generation business units. He served as the Company's Executive Vice President and Chief Financial Officer from 2007 to 2008 and Executive Vice President, Chief Financial Officer, and Treasurer from 2003 to 2007, where he was responsible for the Company's accounting, finance, tax, investor relations, treasury, and risk management functions. In those roles, he also served as the chief risk officer and had responsibility for corporate strategy. Mr. Fanning is on the Boards of a number of Southern Company's subsidiaries. He is also a Director of the Federal Reserve Bank of Atlanta, serving as Deputy Chair of the Board, Chair of the Audit Committee, and as a member of the Executive Committee. Mr. Fanning served on the Board of The St. Joe Company from 2005 through September 2011. Mr. Fanning's knowledge of the Company's business and the electric utility industry, understanding of the complex regulatory structure of the industry, and experience in strategy development and execution uniquely qualify him to be the Chairman of the Board.

David J. Grain
Age: 51
Director since: 2012
Board committee: Audit
Principal occupation: Founder and Managing Partner, Grain Management, LLC, private equity firm
Other directorships: Gateway Bank of Southwest Florida

Director qualifications: Mr. Grain is the Founder and Managing Partner of Grain Management, LLC, a private equity firm specializing in investments in wireless communications infrastructure throughout the United States, since 2006. He is also the Chief Executive Officer of Grain Communications Group, Inc. Grain Management, LLC's flagship funds manage capital on behalf of domestic institutional investors including academic endowments, public pension funds, and foundations. Before forming the Grain entities, Mr. Grain served as President of Global Signal, Inc., where he was hired to lead Pinnacle Holdings, Inc. (Pinnacle) from bankruptcy through its successful operational turnaround. After Pinnacle was renamed Global Signal, Inc. in 2004, Mr. Grain grew the company into one of the largest independent wireless communications tower companies in North America. In 2011, Mr. Grain was appointed by President Obama to the National Infrastructure Advisory Council. He previously served as chairman of the Florida

State Board of Administration Investment Advisory Council as an appointee of former Governor Charlie Crist. He is a Director of the Gateway Bank of Southwest Florida and a Trustee of College of the Holy Cross. Mr. Grain's background in finance, investment management, wireless communications infrastructure, leadership, and civic involvement are valuable to the Board.

Veronica M. Hagen
Age: 68
Director since: 2008; Presiding Director effective May 28, 2014
Board committees: Compensation and Management Succession (Chair), Nuclear/Operations
Other directorships: Polymer Group, Inc., Newmont Mining Corporation

Director qualifications: Ms. Hagen retired in August 2013 from her position as President and Chief Executive Officer of Polymer Group, Inc. She continues to serve as a Director of Polymer Group, Inc. Ms. Hagen had served as Director and Chief Executive Officer of Polymer Group, Inc. since April 2007 and as President since January 2011. Polymer Group, Inc. is a leading producer and marketer of engineered materials. Prior to joining Polymer Group, Inc., Ms. Hagen was the President and Chief Executive Officer of Sappi Fine Paper, a division of Sappi Limited, the South African-based global leader in the pulp and paper industry, from November 2004 until her resignation in 2007. She also has served as Vice President and Chief Customer Officer at Alcoa Inc. and owned and operated Metal Sales Associates, a privately-held metal business. Ms. Hagen also serves on the Environmental, Social Responsibility, and Safety Committee and the Compensation Committee of the Board of Newmont Mining Corporation. Ms. Hagen's global operational management experience and commercial business leadership are valuable assets to the Board.

Warren A. Hood, Jr.

Age: 62

Director since: 2007

Board committee: Audit

Principal occupation: Chairman of the Board and Chief Executive Officer of Hood Companies, Inc., packaging and construction products

Other directorships: Hood Companies, Inc., BancorpSouth, Inc. (formerly a Director of Mississippi Power Company)

Director qualifications: Mr. Hood is the Chairman and Chief Executive Officer of Hood Companies Inc. which he established in 1978. Hood Companies Inc. consists of four separate corporations with 60 manufacturing and distribution sites throughout the United States, Canada, and Mexico. Hood Companies, Inc.'s products are currently marketed in North America, the Caribbean, and Western Europe. Mr. Hood previously served on the Board of the Company's subsidiary, Mississippi Power Company (Mississippi Power), where he was also a member of the Compensation Committee. Mr. Hood has long been recognized for his leadership role in the State of Mississippi. He serves or has served on numerous corporate, community, and philanthropic boards, including Boy Scouts of America Pine Burr Area Council, Governor Phil Bryant's Mississippi Works Committee, and The Governor's Commission on Rebuilding, Recovery and Renewal, which was formed following Hurricane Katrina in 2005. He serves on the Board of BancorpSouth, Inc. where he is a member of the Audit Committee. Mr. Hood's business operations, risk management, financial experience, and civic involvement are valuable to the Board.

Linda P. Hudson

Age: 63

Director since: 2014

Board committee: Audit

Other directorships: BAE Systems, Inc., Bank of America Corporation

Director qualifications: From October 2009 through February 2014, Ms. Hudson served as the President and Chief Executive Officer of BAE Systems, Inc., a U.S.-based global defense, aerospace, and security company. BAE Systems, Inc. is a wholly-owned subsidiary of London-based BAE Systems plc. Previously, Ms. Hudson served as President of BAE Systems' Land & Armaments operating group, the world's largest military vehicle and equipment business. Before joining BAE Systems in 2006, she served as Vice President of the General Dynamics Corporation and President of General Dynamics Armament and Technical Products. She currently serves as an adviser and outside Director for BAE Systems, Inc. She is also a member of Bank of America Corporation's Board of Directors where she serves on the Compensation and Benefits Committee and the Credit Committee. Ms. Hudson's experience leading a large, highly-regulated, complex business and expertise in engineering, technology, operations, and risk management are valuable to the Board.

Donald M. James

Age: 65

Director since: 1999

Board committees: Finance, Governance

Principal occupation: Chairman of the Board and Chief Executive Officer of Vulcan Materials Company, construction materials

Other directorships: Vulcan Materials Company, Wells Fargo & Company (formerly a Director of Protective Life Corporation)

Director qualifications: Mr. James joined Vulcan Materials Company in 1992 as Senior Vice President and General Counsel and then became President of the Southern Division and then Senior Vice President of the Construction Materials Group and President of the Southern Division. Prior to joining Vulcan Materials Company, Mr. James was a partner at the law firm of Bradley, Arant, Rose & White for 10 years. Mr. James is also a Director of the UAB Health System, Boy Scouts of Central Alabama, and the Economic Development Partnership of Alabama, Inc. In addition, he serves on the Finance and Human Resources Committees of Wells Fargo & Company's Board of Directors.
Mr. James' leadership of a large public company, his legal expertise, and his civic involvement are valuable assets to the Board.

Dale E. Klein

Age: 66

Director since: 2010

Board committees: Governance, Nuclear/Operations

Principal occupation: Associate Vice Chancellor of Research of the University of Texas System since 2011 and Associate Director of the Energy Institute at The University of Texas at Austin since 2010, university system

Other directorships: Pinnacle West Capital Corporation, Arizona Public Service Company

Director qualifications: Dr. Klein was Commissioner from 2009 to 2010 and Chairman from 2006 through 2009 of the U.S. Nuclear Regulatory Commission. Dr. Klein also served as Assistant to the Secretary of Defense for Nuclear, Chemical, and Biological Defense Programs from 2001 through 2006. Dr. Klein has more than 35 years of experience in the nuclear energy industry. Dr. Klein began his career at the University of Texas in 1977 as a professor of mechanical engineering which included a focus on the university's nuclear program. He spent nearly 25 years in various teaching and leadership positions — including Director of the nuclear engineering teaching laboratory, associate dean for research and administration in the College of Engineering, and vice-chancellor for special engineering programs. He serves on the Audit and Nuclear and Operating Committees of Pinnacle West Capital Corporation, an Arizona energy company, and is a member of the Board of Pinnacle West Capital Corporation's principal subsidiary, Arizona Public Service Company. Dr. Klein's expertise in nuclear energy regulation and operations, technology, and safety is valuable to the Board.

William G. Smith, Jr.

Age: 60

Director since: 2006, Presiding Director since May 23, 2012

Board committees: Compensation and Management Succession, Finance

Principal occupation: Chairman of the Board, President, and Chief Executive Officer of Capital City Bank Group, Inc., banking

Other directorships: Capital City Bank Group, Inc., Capital City Bank

Director qualifications: Mr. Smith began his career at Capital City Bank in 1978, where he worked in a number of positions of increasing responsibility before being elected President and Chief Executive Officer of Capital City Bank Group, Inc. in January 1989. He was elected Chairman of the Board of the Capital City Bank Group, Inc. in 2003. He is also the Chairman and Chief Executive Officer of Capital City Bank. He has also served on the Board of Directors of the Federal Reserve Bank of Atlanta. He is the former Federal Advisory Council Representative for the Sixth District of the Federal Reserve System and past Chair of both Tallahassee Memorial HealthCare and the Tallahassee Area Chamber of Commerce. Mr. Smith's experience in finance, business operations, and risk management is valuable to the Board.

Steven R. Specker

Age: 68

Director since: 2010

Board committees: Governance, Nuclear/Operations

Other directorships: Trilliant Incorporated

Director qualifications: Dr. Specker served as President and Chief Executive Officer of the Electric Power Research Institute (EPRI) from 2004 until his retirement in 2010. Prior to joining EPRI, Dr. Specker founded Specker Consulting, LLC, a private consulting firm, which provided operational and strategic planning services to technology companies serving the global electric power industry. Dr. Specker also served in a number of leadership positions during his 30-year career at General Electric Company (GE), including serving as President of GE's nuclear energy business, President of GE digital energy, and Vice President of global marketing. Dr. Specker is also a member of the Board of Trilliant Incorporated, a leading provider of Smart Grid communication solutions. Dr. Specker brings to the Board a keen understanding of the electric industry and valuable insight in innovation and technology development.

E. Jenner Wood III

Age: 62

Director since: 2012

Board committees: Governance, Nuclear/Operations

Principal occupation: Chairman, President, and Chief Executive Officer of the Atlanta Division of SunTrust Bank and Executive Vice President of SunTrust Banks, Inc., banking

Other directorships: Oxford Industries, Inc. (formerly a Director of Crawford & Company and Georgia Power)

Director qualifications: Mr. Wood is currently the Chairman, President, and Chief Executive Officer of the Atlanta Division of SunTrust Bank, a position he has held since April 2014, where he is responsible for managing retail, commercial, and private wealth banking in the Greater Atlanta area. He also has served as an Executive Vice President of SunTrust Banks, Inc. since July 2005. From April 2010 through January 2013, he was Chairman of the Board, President, and Chief Executive Officer of the Atlanta/Georgia Division of SunTrust Bank and from January 2013 through March 2014 he was Chairman of the Board, President, and Chief Executive Officer of the Georgia/North Florida Division of SunTrust Bank. From 2002 through 2010, he served as Chairman, President, and Chief Executive Officer of SunTrust Bank Central Group with responsibility over Georgia and Tennessee. Mr. Wood has more than 38 years of experience in the banking industry and has served in numerous management positions in corporate and trust and investment management with SunTrust Banks, Inc. He served as a member of the Board of Georgia Power, the largest subsidiary of the Company, from 2002 until May 2012. During his tenure on the Georgia Power Board, he served as a member of the Compensation, Executive, and Finance Committees. Mr. Wood is a Director of Oxford Industries, Inc., where he serves as Presiding Director and as a member of the Executive Committee. He is a past member of the Board of Crawford & Company, where he served as a member of the Compensation Committee and the Audit Committee. He is active in numerous civic and community organizations serving as a Trustee of the Robert W. Woodruff Foundation, The Sartain Lanier Family Foundation, Camp-Younts Foundation, and the Jesse Parker Williams Foundation. Mr. Wood's leadership experience and extensive background in finance as well as his involvement in the community are beneficial to the Board.

Each nominee has served in his or her present position for at least the past five years, unless otherwise noted.
The affirmative vote of a majority of the votes cast is required for the election of Directors at any meeting for the election of Directors at which a quorum is present. A majority of the votes cast means that the number of shares voted "FOR" the election of a Director must exceed the number of votes cast "AGAINST" the election of that Director.
THE BOARD OF DIRECTORS RECOMMENDS A VOTE "FOR" THE NOMINEES LISTED IN ITEM NO. 1.
ITEM NO. 2 — RATIFICATION OF APPOINTMENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM
The Audit Committee of the Board of Directors has appointed Deloitte & Touche LLP (Deloitte & Touche) as the Company's independent registered public accounting firm for 2014. This appointment is being submitted to stockholders for ratification. Representatives of Deloitte & Touche will be present at the Annual Meeting to respond to appropriate questions from stockholders and will have the opportunity to make a statement if they desire to do so.
The affirmative vote of a majority of the votes cast is required for ratification of the appointment of the independent registered public accounting firm.
THE BOARD OF DIRECTORS RECOMMENDS A VOTE "FOR" ITEM NO. 2.
ITEM NO. 3 — ADVISORY VOTE ON NAMED EXECUTIVE OFFICERS' COMPENSATION
(the Say-on-Pay vote)
At the 2013 Annual Meeting of Stockholders, the Company provided stockholders with the opportunity to cast an advisory vote regarding the compensation of the named executive officers as disclosed in the 2013 Proxy Statement for the 2013 Annual Meeting of Stockholders. At the meeting, stockholders strongly approved the proposal, with more than 94% of the votes cast voting in favor of the proposal. At the 2011 Annual Meeting, stockholders were asked how frequently the Company should hold a say-on-pay vote - whether every one, two, or three years. Consistent with the recommendation of the Board of Directors, stockholders indicated their preference to hold a say-on-pay vote annually. In light of the Board of Directors' recommendation and the strong support of the Company's stockholders, the Board of Directors determined to hold a say-on-pay vote annually.
As described in the Compensation Discussion & Analysis (CD&A) in this Proxy Statement, the Compensation Committee has structured the Company's executive compensation program based on the belief that executive compensation should:

- Be competitive with the Company's industry peers;
- Motivate and reward achievement of the Company's goals;
- Be aligned with the interests of the Company's stockholders and its subsidiaries' customers; and
- Not encourage excessive risk-taking.

The Company believes these objectives are accomplished through a compensation program that provides the appropriate mix of fixed and short- and long-term performance-based compensation that rewards achievement of the Company's financial success, business unit financial and operational success, and total shareholder return. The Company's financial and operational achievement in 2013 resulted in performance-based awards that were aligned with performance.
All decisions concerning the compensation of the Company's named executive officers are made by the Compensation Committee, an independent Board committee, with the advice and counsel of an independent executive compensation consultant, Pay Governance.
The Company encourages stockholders to read the Executive Compensation section of this Proxy Statement which includes the CD&A, the Summary Compensation Table, and other related compensation tables, including the information accompanying these tables.
Although it is non-binding on the Board of Directors, the Compensation Committee will review and consider the vote results when making future decisions about the Company's executive compensation program.

The affirmative vote of a majority of the votes cast is required for approval of the following resolution:
"RESOLVED, that the Company's stockholders approve, on an advisory basis, the compensation of the Company's named executive officers, as disclosed in the Proxy Statement for the 2014 Annual Meeting of Stockholders pursuant to the compensation disclosure rules of the Securities and Exchange Commission, including the Compensation Discussion and Analysis, the 2013 Summary Compensation Table, and the other related tables and accompanying narrative set forth in the Proxy Statement."
THE BOARD OF DIRECTORS RECOMMENDS A VOTE "FOR" ITEM NO. 3.

ITEM NO. 4 - STOCKHOLDER PROPOSAL ON AN INDEPENDENT BOARD CHAIR

The Company has been advised that John C. Liu, Comptroller, City of New York, on behalf of the New York City Employees' Retirement System, the New York City Fire Department Pension Fund, the New York City Teachers' Retirement System, the New York City Police Pension Fund, and the New York City Board of Education Retirement System (collectively, the Systems), 1 Centre Street, New York, New York 10007-2341, collectively holders of 1,693,034 shares of Common Stock, proposes to submit the following resolution at the 2014 Annual Meeting.

"RESOLVED: Shareholders of Southern Company request that the Board of Directors adopt a policy that the Chair of the Board of Directors shall be an independent director who is not a current or former employee of the company, and whose only nontrivial professional, familial or financial connection to the corporation or its CEO is the directorship. The policy should be implemented so as not to violate existing agreements and should allow for departure under extraordinary circumstances such as the unexpected resignation of the chair."
Supporting Statement
"The role of the CEO is to run the company. The role of the board of directors is to provide independent oversight of management and the CEO.
"At present, the Company's CEO also serves as chairman of the board, a conflict of interest that we believe can result in excessive management influence on the board and weaken the board's independent oversight of management. The consequences can include higher executive compensation, lower shareholder returns, more aggressive risk-taking, and ultimately less sustainable companies for the long-term.
"According to a June 2012 study of 180 North American companies with market capitalization over $20 billion ("The Costs of a Combined Chair/CEO," GMI Ratings), shareholders pay out more when there is a non-independent chair at the helm. The median total compensation paid to a combined chair/CEO was $16.1 million, 73% more than the $9.3 million paid in total to the positions of CEO and an independent chair.
"Companies with a separate chair (independent or non-independent) and CEO also appear to perform better and to be more sustainable over the longer term, according to the GMI study. The 5-year total shareholder return was found to be 28% higher, and the GMI risk ratings lower, at these companies.
"Board leadership structure in the U.S. is trending towards an independent chair. Twenty-one percent of S&P 500 companies now have an independent chair compared to 9% in 2003 (Spencer Stuart Board Index). Approximately 73% of directors on boards with an independent chair believe that their companies benefited from the split (Survey, 2008 Public US National Associate of Corporate Directors) and more than 88% of senior financial executives believe the positions should be separated (Grant Thornton, 2009 Survey).
"Despite these strides, the U.S. lags the rest of the world in adopting this best practice. Companies with independent board chairs comprise 76% of FTSE 100 index in the United Kingdom, 55% of the Toronto Stock Exchange 60, and 50% for German DAX 30 index, according to findings by Deloitte (Board Leadership: A Global Perspective, 2011).
"We urge shareholders to support this proposal for an independent board chairman."
THE BOARD OF DIRECTORS RECOMMENDS A VOTE "AGAINST" ITEM NO. 4 FOR THE FOLLOWING REASONS:
Overview. Part of the Directors' fiduciary duties is to determine that the Board's leadership structure is appropriate given the Company's specific characteristics or circumstances at the time. The Company's Bylaws provide the Board

with maximum

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flexibility to determine the most appropriate leadership structure of the Company, including, when appropriate, separating the positions of the Chairman of the Board and the Chief Executive Officer. The Board believes that the Company and its stockholders benefit from this flexibility and that the Board is best positioned to lead this evaluation since the Board has extensive knowledge of the Company's strategic goals, opportunities, and challenges. The Company has reviewed current practices and trends in this area and has not found persuasive evidence that separating the positions results in better corporate performance or board effectiveness. Thus, the Board believes that it is important for the Board to continue to determine on a case-by-case basis the most effective leadership structure for the Company, rather than take the "one-size-fits-all" approach to Board leadership requested by this stockholder proposal.

Board Structure. The Board believes that its current leadership structure, which has a combined role of Chief Executive Officer and Chairman counterbalanced by a strong independent Board led by a Presiding Director, is most suitable for the Company at this time. The combined role of Chief Executive Officer and Chairman is held by Mr. Fanning who is the Director most familiar with the Company's business and industry, including the regulatory structure and other industry-specific matters, and therefore, most capable of effectively identifying strategic priorities and leading discussion and execution of strategy.

With the exception of Mr. Fanning, all Directors are independent based on the independence standards of the NYSE. Each of the committees of the Board is comprised only of independent Directors. The Board believes that at the present time this leadership structure strikes the optimal balance between unified leadership and effective independent oversight of management.

Strong Presiding Director. The Company's Corporate Governance Guidelines provide for a Presiding Director that is selected by and from the independent Directors bi-annually. This structure has been in place for over a decade. Mr. Smith has served as the Presiding Director since the 2012 Annual Meeting of Stockholders. In February 2014, the independent Directors appointed Ms. Hagen to serve as the Presiding Director effective May 28, 2014 until the Company's 2016 Annual Meeting of Stockholders.

With respect to the roles and responsibilities of the Presiding Director, the Company's Corporate Governance Guidelines provide that:

- independent Directors meet in executive session, without management, at least quarterly, and at other times deemed appropriate by the Presiding Director or two or more other independent Directors;
- the Presiding Director chairs executive sessions and serves as the principal liaison between the Chairman and the independent Directors; however, each Director has direct and complete access to the Chairman at any time;
- the Presiding Director meets regularly with the Chairman;
- the Presiding Director serves as the primary contact Director for stockholders and other interested parties;
- the Presiding Director is involved in communicating any sensitive issues to the Directors; and
- the Presiding Director chairs Board meetings in the absence of the Chairman.

Corporate Governance Practices. The Company's existing corporate governance practices provide for strong independent leadership on the Board with effective oversight of management of the Company's business. As stated in the Company's Corporate Governance Guidelines, it is the duty of the Board to serve as a prudent fiduciary for stockholders and to oversee the management of the Company's business. Additionally, the Board has broad responsibility to provide oversight of significant risks to the Company, primarily through direct engagement with Company management and delegation of ongoing risk oversight responsibilities to the applicable committee.

The Board currently has 13 non-employee Directors, all of whom, including the Presiding Director, are independent based on NYSE independence standards. Other than Mr. Fanning, none of the Directors is a current or former employee of the Company or any of its subsidiaries.

The Board meets regularly in executive session without the Chief Executive Officer present. In 2013, the Board held six regularly scheduled meetings, all of which included an executive session chaired by the Presiding Director. Topics discussed include strategic matters, management succession, board evaluation, Chief Executive Officer performance, and other topical matters. Additionally, the Presiding Director meets regularly with the Chairman and Chief Executive Officer outside of Board meetings to discuss various matters.

The Company's Corporate Governance Guidelines provide that the Chairman of the Board and the Corporate Secretary will solicit input from all independent Directors, including the Presiding Director, in establishing the agenda for Board meetings. Additionally, committee chairs, all of whom are independent, provide significant input in establishing the agendas for their committee meetings. All Directors are encouraged to request agenda items, additional information, and/or modifications to schedules as they deem appropriate.

These existing corporate governance practices ensure that the Board maintains strong independent leadership to oversee the management of the Company's business and best serve the Company's stockholders.

Oversight of Chief Executive Officer Performance. The stockholder proposal attempts to justify imposing a "one-size-fits-all" approach to Board leadership in part by criticizing compensation practices for the combined Chief Executive Officer and Chairman position. The Compensation Committee Charter provides that the Compensation Committee, comprised entirely of independent Directors, evaluate the performance of the Chief Executive Officer at least annually and review it with the independent Directors, annually review a tally sheet of all components of the Chief Executive Officer's total compensation, and recommend the compensation level of the Chief Executive Officer for approval by the independent Directors. Additionally, Pay Governance, an independent executive compensation consultant, provides advice and counsel concerning the compensation of the Chief Executive Officer to the Compensation Committee, including benchmarking analysis, and meets with the members in executive session at every regular meeting of the Compensation Committee. Further, at the Company's 2013 and 2012 Annual Meetings of Stockholders, more than 94% and 95%, respectively, of the votes cast voted to approve the compensation provided to the Company's named executive officers, including the Chief Executive Officer. The Company's process provides effective, independent oversight of the Chief Executive Officer's performance.

Conclusion. Given the Board's structure and its oversight of the management of the Company's business discussed above, the Board believes that adopting a "one-size-fits-all" standard that the Chairman of the Board must be an independent Director is not necessary for effective independent Board leadership. The Board believes that the Company and its stockholders benefit from the flexibility that currently exists in determining whether to separate or combine the roles of Chairman and Chief Executive Officer.

The vote needed to pass the proponent's resolution is the affirmative vote of a majority of the votes cast.

THE BOARD OF DIRECTORS RECOMMENDS A VOTE "AGAINST" ITEM NO. 4.

Audit Committee Report

The Audit Committee oversees the Company's financial reporting process on behalf of the Board of Directors. Management has the primary responsibility for establishing and maintaining adequate internal controls over financial reporting, including disclosure controls and procedures, and for preparing the Company's consolidated financial statements. In fulfilling its oversight responsibilities, the Audit Committee reviewed the audited consolidated financial statements of the Company and its subsidiaries and management's report on the Company's internal control over financial reporting in the 2013 Annual Report to Stockholders attached hereto as Appendix B with management. The Audit Committee also reviews the Company's quarterly and annual reporting on Forms 10-Q and 10-K prior to filing with the SEC. The Audit Committee's review process includes discussions of the quality, not just the acceptability, of the accounting principles, the reasonableness of significant judgments and estimates, and the clarity of disclosures in the financial statements.

The independent registered public accounting firm is responsible for expressing opinions on the conformity of the consolidated financial statements with accounting principles generally accepted in the United States and the effectiveness of the Company's internal control over financial reporting with the criteria established in "Internal Control — Integrated Framework (1992)" issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Audit Committee has discussed with the independent registered public accounting firm the matters that are required to be discussed by the Public Company Accounting Oversight Board (PCAOB) Auditing Standard No. 16, Communications with Audit Committees and SEC Rule 2-07 of Regulation S-X, Communications with Audit Committees. In addition, the Audit Committee has discussed with the independent registered public accounting firm its independence from management and the Company as required under rules of the PCAOB and has received the written disclosures and letter from the independent registered public accounting firm required by the rules of the PCAOB. The Audit Committee also has considered whether the independent registered public accounting firm's provision of non-audit services to the Company is compatible with maintaining the firm's independence.

The Audit Committee discussed the overall scope and plans with the Company's internal auditors and independent registered public accounting firm for their respective audits. The Audit Committee meets with the internal auditors and the independent registered public accounting firm, with and without management present, to discuss the results of their audits, evaluations by management and the independent registered public accounting firm of the Company's internal control over financial reporting, and the overall quality of the Company's financial reporting. The Audit Committee also meets privately with the Company's compliance officer. The Audit Committee held 10 meetings during 2013.

In reliance on the reviews and discussions referred to above, the Audit Committee recommended to the Board of Directors (and the Board approved) that the audited consolidated financial statements be included in the Company's Annual Report on Form 10-K for the year ended December 31, 2013 and filed with the SEC. The Audit Committee also reappointed Deloitte & Touche as the Company's independent registered public accounting firm for 2014. Stockholders will be asked to ratify that selection at the 2014 Annual Meeting.

Members of the Audit Committee as of December 31, 2013:

Jon A. Boscia, Chair
David J. Grain
Warren A. Hood, Jr.

PRINCIPAL INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM FEES

The following represents the fees billed to the Company for the two most recent fiscal years by Deloitte & Touche — the Company's principal independent registered public accounting firm for 2013 and 2012.

	2013	2012
	(in thousands)	
Audit Fees (1)	$ 11,704	$ 11,695
Audit-Related Fees (2)	110	500
Tax Fees	50	0
All Other Fees (3)	29	31
Total	$ 11,893	$ 12,226

(1) Includes services performed in connection with financing transactions.

(2) Includes non-statutory audit services in both 2013 and 2012.

(3) Represents registration fees for attendance at Deloitte & Touche-sponsored education seminars, subscription fees for Deloitte & Touche's technical accounting research tool, and travel expenses for Deloitte & Touche's training facilitator.

The Audit Committee has adopted a Policy on Engagement of the Independent Auditor for Audit and Non-Audit Services (see Appendix A) that includes requirements for the Audit Committee to pre-approve services provided by Deloitte & Touche. This policy was initially adopted in July 2002 and, since that time, all services included in the chart above have been pre-approved by the Audit Committee.

Index to Executive Compensation

COMPENSATION DISCUSSION AND ANALYSIS (CD&A)

This section describes the compensation program for the Company's Chief Executive Officer and Chief Financial Officer in 2013, as well as each of the Company's other three most highly compensated executive officers serving at the end of the year. Collectively, these officers are referred to as the named executive officers.

Thomas A. Fanning	Chairman of the Board, President, and Chief Executive Officer
Art P. Beattie	Executive Vice President and Chief Financial Officer
W. Paul Bowers	Executive Vice President of the Company and President and Chief Executive Officer of Georgia Power
Kimberly S. Greene (1)	Executive Vice President of the Company and President and Chief Executive Officer of Southern Company Services, Inc. (SCS)
Charles D. McCrary (2)	Executive Vice President of the Company and President and Chief Executive Officer of Alabama Power Company (Alabama Power)

(1) Effective March 1, 2014, Ms. Greene resigned the roles of President and Chief Executive Officer of SCS and was elected Executive Vice President and Chief Operating Officer of the Company.

(2) Effective March 1, 2014, Mr. McCrary resigned the roles of President and Chief Executive Officer of Alabama Power and was elected Chairman of Alabama Power's Board of Directors until his retirement on May 1, 2014.

Executive Summary

Performance

Performance-based pay represents a substantial portion of the total direct compensation paid or granted to the named executive officers for 2013.
(1) Salary is the actual amount paid in 2013, Short-Term Performance Pay is the actual amount earned in 2013 based on performance, and Long-Term Performance Pay is the value on the grant date of stock options and performance shares granted in 2013. See the Summary Compensation Table for the amounts of all elements of reportable compensation described in this CD&A.

Business unit financial and operational and Company earnings per share (EPS) goal results for 2013 are shown below:

EPS: 0% of Target	Financial: 110% of Target	Operational: 161% of Target

The Company's annualized total shareholder return has been:

1-Year: 0.49%	3-Year: 7.22%	5-Year: 7.22%

These levels of achievement resulted in payouts that were aligned with performance.

Compensation and Benefit Beliefs

The Company's 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 the Company's executive compensation program should:

- Be competitive with the Company's industry peers;
- Motivate and reward achievement of the Company's goals;
- Be aligned with the interests of the Company's stockholders and its subsidiaries' 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 the Company's business goals. The Company believes that focusing on the customer drives achievement of financial objectives and delivery of a premium, risk-adjusted total shareholder return for the Company's stockholders. Therefore, short-term performance pay is based on achievement of the Company's operational and financial performance goals, with one-third determined by operational performance, such as safety, reliability, and customer satisfaction; one-third determined by business unit financial performance; and one-third determined by EPS performance. Long-term performance pay is tied to stockholder value, with 40% of the target value awarded in stock options, which reward stock price appreciation, and 60% awarded in performance shares, which reward 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 by the Compensation Committee of an independent compensation consultant, Pay Governance, that provides no other services to the 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 ongoing perquisites with no income tax gross-ups, except on certain relocation-related benefits.
- "No-hedging" provision in the Company's insider 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 executive compensation program. In doing so, the Compensation Committee uses information from others, principally Pay Governance. The Compensation Committee also relies on information from the Company's Human Resources staff and, for individual executive officer performance, from the Company's Chief Executive Officer. 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 the Company's executive compensation at the 2013 Annual Meeting of Stockholders. In light of the significant support of the stockholders (94% 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 Company's executive compensation program is competitive, aligned with the Company's financial and operational performance, and in the best interests of the Company, its stockholders, and its subsidiaries' customers.

Executive Compensation Focus

The executive compensation program places significant focus on rewarding performance. The program is performance-based in several respects:

- Company EPS and business unit financial and operational performance, based on actual results compared to target performance levels established early in the year, determine the actual payouts under the short-term (annual) performance-based compensation program (Performance Pay Program).
- Common Stock price changes result in higher or lower ultimate values of stock options.
- 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, the Company has no general employment contracts or guaranteed severance with the named executive officers, except upon a change in control.

The pay-for-performance principles apply not only to the named executive officers but to thousands of employees. The Performance Pay Program covers almost all of the more than 26,000 employees of the Southern Company system. Stock options and performance shares are granted to approximately 3,300 employees of the Southern Company system. These programs engage employees, which ultimately is good not only for them, but also for the Company and its stockholders.

OVERVIEW OF EXECUTIVE COMPENSATION COMPONENTS

The primary components of the 2013 executive compensation program are shown below:

The Company'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 performance-based compensation includes stock options, performance shares, and, in some cases, restricted stock units. The performance-based compensation components are linked to the Company's financial and operational performance, Common Stock performance, and 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

Pay Governance develops and presents to the Compensation Committee competitive market-based compensation levels for each of the named executive officers. The market-based compensation levels are developed from a size-appropriate energy services executive compensation survey database. The survey participants are utilities with revenues of $6 billion or more. The Compensation Committee reviews the data and uses it in establishing market-based compensation levels for the named executive officers.

Ameren Corporation	GDF SUEZ North America
American Electric Power Company, Inc.	Kinder Morgan, Inc.
Bg US Services, Inc.	MidAmerican Energy Company
CenterPoint Energy, Inc.	Next Era Energy, Inc.
CMS Energy Corporation	NRG Energy, Inc.
Consolidated Edison, Inc.	PG&E Corporation
Dominion Resources, Inc.	PPL Corporation
DTE Energy Company	Progress Energy, Inc.
Duke Energy Corporation	Public Service Enterprise Group Inc.
Edison International	Sempra Energy
Enbridge Energy Partners, LP	Targa Resources Corp.
Energy Future Holdings Corp.	Tennessee Valley Authority
Entergy Corporation	UGI Corporation
Enterprise Products Partners L.P.	The AES Corporation
Exelon Corporation	The Williams Companies, Inc
First Energy Corp.	Xcel Energy Inc.

The Company is one of the largest utility holding companies in the United States based on revenues and market capitalization, and its largest business units are some of the largest in the industry as well. For that reason, Pay Governance uses size-appropriate survey market data in order to fit it to the scope of the Company's business.

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 responsibilities. Based on that 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 the 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 2013 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, 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 2013 for each named executive officer. As the chart below depicts, the fixed pay (base salary) for Mr. Fanning is 15% of his total target compensation opportunity and ranges from 25% to 30% for the other named executive officers. Variable (at risk) performance-based compensation is 85% for Mr. Fanning and 70% to 75% for the other named executive officers.
The salary levels shown above were not effective until March 2013. 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 2013. For Ms. Greene, the salary level shown is the amount approved by the Compensation Committee effective on her date of employment (April 1, 2013). The target annual performance-based compensation amount shown for Ms. Greene is the full year target amount that would have been granted to her had she been employed the entire year by the Southern Company system.

For purposes of comparing the value of the compensation program to the market data, stock options are valued at $2.92 per option and performance shares at $40.50 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, except for Ms. Greene. For 2013, Ms. Greene received stock options only because she was hired after performance shares were granted.

In 2012, Pay Governance analyzed the level of actual payouts for 2011 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 2013. That analysis was updated in 2013 by Pay Governance for 2012 performance, and those findings were used in establishing goals for 2014.

DESCRIPTION OF KEY COMPENSATION COMPONENTS

2013 Base Salary

Most employees, including all of the named executive officers except Ms. Greene (who was hired in 2013), received base salary increases in 2013. Base salary increases for each of the named executive officers, except Ms. Greene, were recommended in 2013 for the Compensation Committee's approval by Mr. Fanning, except for his own salary. Those recommendations took into account the market data provided by the Compensation Committee's independent compensation consultant, as well as 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 achievement of financial and operational goals in prior years. The Compensation Committee approved the recommended salaries in 2013.

Base salaries were increased 3% for Messrs. Fanning and Beattie. Base salaries for Messrs. Bowers and McCrary were increased 2.8%.

2013 Performance-Based Compensation

This section describes performance-based compensation for 2013.

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 the Company's stockholders in the short- and long- term. Operational excellence and business unit and Company financial performance are integral to the achievement of business results that benefit customers and stockholders.

Therefore, in 2013, the Company strove for and rewarded:

- Continuing industry-leading reliability and customer satisfaction, while maintaining reasonable retail prices;
- Meeting energy demand with the best economic and environmental choices;
- Return on equity (ROE) – target performance level in the top quartile of comparable electric utilities;
- Dividend growth;
- Long-term, risk-adjusted total shareholder return; and
- Financial integrity — an attractive risk-adjusted return and sound financial policy.

The performance-based compensation program is designed to encourage achievement of these goals.

Mr. Fanning, with the assistance of the Company's Human Resources staff, recommended to the Compensation Committee the program design and award amounts for senior management, including the named executive officers (other than Mr. Fanning).

2013 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 the Southern Company system, including the named executive officers, are participants.

The performance goals are set at the beginning of each year by the Compensation Committee.

- EPS is defined as the Company's net income from ongoing business activities divided by average shares outstanding during the year. The EPS performance measure is applicable to all participants in the Performance Pay Program.
- For the traditional operating companies (Alabama Power, Georgia Power, Gulf Power Company (Gulf Power), and Mississippi 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 Company (Southern Power), the business unit financial performance goal is net income.

- For the traditional operating companies, operational goals are safety, customer satisfaction, plant availability, transmission and distribution system reliability, and culture. For the nuclear operating company, Southern Nuclear Operating Company, Inc. (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.

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. In 2013, the Company recorded pre-tax charges to earnings of $1.14 billion due to estimated probable losses relating to Mississippi Power's construction of the integrated coal gasification combined cycle facility in Kemper County, Mississippi (Kemper IGCC). Although these charges are not expected to occur with regularity in the future, the Compensation Committee did not exclude the charges with respect to the EPS goal, and, consequently the EPS result was under the threshold performance level that was established at the beginning of the year. As a result, no payout associated with EPS was made to any employee in the Southern Company system, including the named executive officers.

There are over 4,000 Southern Company system employees that provide professional and technical support to all of the Company's subsidiaries. For that reason, the business unit financial goal component for these employees is based largely on corporate-level ROE. Due to the charges described above, Mississippi Power's net income was negative $477 million and, therefore, its ROE was below the threshold performance level established, which resulted in a zero payout on the business unit financial goal for Mississippi Power employees. Additionally, the impact of Mississippi Power's negative net income also resulted in a corporate-level ROE that was below the threshold performance level established by the Compensation Committee. Therefore, for employees paid based on corporate-level ROE, including Ms. Greene and Messrs. Fanning and Beattie, this would have resulted in no payout for corporate-level ROE, despite above-threshold achievement at the other business units supported by these employees. For that reason, the Compensation Committee believed that a zero payout on the corporate-level ROE component was not an equitable result for those employees and amended the methodology for calculating corporate-level ROE from an aggregate ROE to a weighted average payout, which is the methodology that was used under the annual performance-based pay program prior to 2010. See Calculating Payouts in this CD&A for a full description of how payouts were calculated for Ms. Greene and Messrs. Fanning and Beattie.

Under the terms of the program, no payout can be made if the Company's current earnings are not sufficient to fund the Common Stock dividend at the same level or higher than the prior year (dividend funding mechanism). In 2013, the Compensation Committee clarified that the dividend funding mechanism was not intended to apply when earnings are insufficient due to items not expected to occur with regularity that do not impact the Company's financial ability to fund the Common Stock dividend, such as the Kemper IGCC charges described above.

Goal Details

Financial Performance Goals	Description	Why It Is Important
EPS	The Company's net income from ongoing business activities divided by average shares outstanding during the year.	Supports commitment to provide stockholders solid, risk-adjusted returns.
Business Unit ROE/Net Income	For the traditional operating companies, 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.	Supports delivery of stockholder value and contributes to the Company's sound financial policies and stable credit ratings.

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, as well as a ranking for each customer segment: residential, commercial, and industrial.	Customer satisfaction is key to operations. Performance of all operational goals affects 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 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 are measured as a percentage of time the nuclear plant is operating. The reliability and availability metrics take generation reductions associated with planned outages into consideration.	Safe and efficient operation of the nuclear fleet is important for delivering clean energy at a reasonable price.
Major Projects - Plant Vogtle Units 3 and 4 and Kemper IGCC	To help ensure construction and licensing of two new nuclear generating units under construction at Georgia Power's Plant Vogtle (Plant Vogtle Units 3 and 4) and the Kemper IGCC are on time, on budget, and in full compliance with all pertinent safety and quality requirements, the Southern Company system has an executive review committee in place for each project to assess progress towards these goals. Each committee may consider a combination of subjective and objective measures to determine their evaluation. Final assessments for each project are approved by the Southern Company Chief Executive Officer and confirmed by the Nuclear/Operations Committee.	Strategic projects enable the Southern Company system to expand capacity to provide clean, affordable energy to customers across the region.
Safety	The Company's Target Zero program is focused on continuous improvement in having a safe work environment. The performance is measured by the applicable company's ranking, as compared to peer utilities in the Southeastern Electric Exchange.	Essential for the protection of employees, customers, and communities.
Culture	The culture goal seeks to improve the Company'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.

The range of EPS, ROE, and Southern Power net income goals for 2013 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)
Maximum	2.87	14.0	215
Target	2.74	12.0	175
Threshold	2.61	9.0	135

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, respectively. For more information on these committees' responsibilities, see the committee descriptions in this Proxy Statement.

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	Plant Vogtle Units 3 and 4 and Kemper IGCC	Culture
Maximum	Top quartile for all customer segments and overall	Significantly exceed targets	Industry best	Significantly exceed targets	Greater than 90th percentile or 5-year Company best	Significantly exceed targets	Significant improvement
Target	Top quartile overall	Meet targets	Top quartile	Meet targets	60th percentile	Meet targets	Improvement
Threshold	2nd quartile overall	Significantly below targets	2nd quartile	Significantly below targets	40th percentile	Significantly below targets	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.

2013 Achievement

Actual 2013 goal achievement is shown in the following tables.

Financial Performance Goal Results

Goal	Result	Achievement Percentage
EPS (from ongoing business activities)	$1.88	0
Alabama Power ROE	13.07%	154
Georgia Power ROE	12.45%	123
Corporate ROE	Weighted Average	113
Southern Power Net Income	$165.5 million	76

Due to the pre-tax charges to earnings related to Mississippi Power's construction of the Kemper IGCC, Southern Company's EPS for 2013 fell below the threshold necessary for payment under the performance pay program. As a result, no payout was associated with the EPS goal.

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Operational Goal Results

Corporate (Ms. Greene and Messrs. Fanning and Beattie)

Company Corporate/Aggregate Goal	Achievement Percentage
Customer Satisfaction	200
Reliability	200
Availability	100
Safety	200
Culture	138
Major Projects - Plant Vogtle Units 3 & 4	175
Major Projects - Kemper IGCC	0
Total Operational Goal Performance Factor	161

Alabama Power (Mr. McCrary)

Goal	Achievement Percentage
Customer Satisfaction	200
Reliability	190
Availability	176
Safety	145
Culture	141
Total Operational Goal Performance Factor	171

Georgia Power (Mr. Bowers)

Goal	Achievement Percentage
Customer Satisfaction	167
Reliability	200
Availability	0
Safety	200
Culture	140
Total Operational Goal Performance Factor	138

Calculating Payouts

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 2013. Targets are set as a percentage of base salary.

All of the named executive officers are paid based on EPS performance. The business unit goals that determine payout levels vary based on the named executive officer's leadership role. For Ms. Greene and Messrs. Fanning and Beattie, payout is based on the weighted average ROE payout results for the traditional operating companies (90%) and Southern Power net income (10%) and the system-wide operational goal results, which includes Southern Nuclear's operational goal results. For Messrs. Bowers and McCrary, payout is based on achievement of the ROE and operational goals of Georgia Power and Alabama Power, respectively.

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 to determine the payout for each named executive officer. The table below shows the calculation of the total performance factor for each of the named executive officers, based on results shown above.

	Southern Company EPS Result (%) 1/3 weight	Business Unit Financial Goal Result (%) 1/3 weight	Business Unit Operational Goal Result (%) 1/3 weight	Total Performance Factor (%)
T. A. Fanning	0	110	161	90
A. P. Beattie	0	110	161	90
W. P. Bowers	0	123	138	87
K. S. Greene	0	110	161	90
C. D. McCrary	0	154	171	108

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 (%)	Target Annual Performance Pay Program Opportunity ($)	Total Performance Factor (%)	Actual Annual Performance Pay Program Payout ($)
T. A. Fanning	115	1,332,563	90	1,199,307
A. P. Beattie	75	485,695	90	437,126
W. P. Bowers	75	573,304	87	498,775
K. S. Greene (1)	70	345,345	90	310,811
C. D. McCrary	75	602,435	108	650,630

(1) Ms. Greene joined the Company in April 2013; therefore, her target Performance Pay Program opportunity was prorated based on the amount of time she was employed in 2013. Her target opportunity would have been $455,000 if she had been employed by the Southern Company system for the entire year.

Long-Term Performance-Based Compensation

2013 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
• Restricted Stock Units
• Used to promote retention of key employees or to attract key employees by replacing award values forfeited upon leaving a former employer
• Continued employment until vesting date(s) is required
• Paid in Common Stock upon vesting

Long-term performance-based awards are intended to promote long-term success and increase stockholder value by directly tying a substantial portion of the named executive officers' total compensation to the interests of stockholders.

Long-term performance-based awards also benefit the Southern Company system's customers by providing competitive compensation that allows the Southern Company system to attract, retain, and engage employees who provide focus on serving customers and delivering safe and reliable electric service.

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's total shareholder return relative to industry peers, as well as Common Stock price. The Compensation Committee also awards restricted stock units occasionally, typically as retention awards or to attract key employees by replacing the value of awards that are forfeited upon leaving a former employer.

The following table shows the grant date fair value of the long-term performance-based awards granted in 2013, except restricted stock units.

	Value of Options ($)	Value of Performance Shares ($)	Total Long-Term Value ($)
T. A. Fanning	2,085,747	3,128,625	5,214,372
A. P. Beattie	531,025	796,514	1,327,539
W. P. Bowers	687,964	1,031,940	1,719,904
K. S. Greene (1)	1,039,997	0	1,039,997
C. D. McCrary	722,922	1,084,347	1,807,269

(1) Ms. Greene was not employed by the Southern Company system when the Compensation Committee granted performance shares and, therefore, her full long-term target value for 2013 was granted in stock options.

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 2013, 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 in the 2013 Annual Report attached as Appendix B to this Proxy Statement (Financial Statements). For 2013, the Black-Scholes value on the grant date was $2.92 per stock option, except for those options granted to Ms Greene. The Black-Scholes value on the grant date for Ms. Greene was $3.16 per stock option.

Performance Shares

2013-2015 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 2013, the value per unit was $40.50. 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, except Ms. Greene. Each performance share unit represents one share of Common Stock.

At the end of the three-year performance period (January 1, 2013 through December 31, 2015), the number of units will be adjusted up or down (0% to 200%) based on the Company's total shareholder return relative to that of its peers in the Philadelphia Utility Index and the custom peer group. The companies in the custom peer group are those that are believed to be most similar to the 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 discussed previously 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 peers 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.	FirstEnergy Corp.
Consolidated Edison, Inc.	NextEra Energy, Inc.
Covanta Holding Corporation	Northeast Utilities
Dominion Resources, Inc.	PG&E Corporation
DTE Energy Company	Public Service Enterprise Group Inc.
Duke Energy Corporation	The AES Corporation
Edison International	Xcel Energy Inc.
El Paso Electric Company	

The peers in the custom peer group on the grant date are listed below.

Alliant Energy Corporation	Northeast Utilities
Ameren Corporation	Pepco Holdings, Inc.
American Electric Power Company, Inc.	PG&E Corporation
CMS Energy Corporation	Pinnacle West Capital Corporation
Consolidated Edison, Inc.	SCANA Corporation
DTE Energy Company	Wisconsin Energy Corporation
Duke Energy Corporation	Xcel Energy Inc.
Edison International	

The scale below will determine the number of units paid in Common Stock following the last year of the performance period, based on the 2013 through 2015 performance period. Payout for performance between points will be interpolated on a straight-line basis.

Performance vs. Peer Groups	Payout (% of Each Performance Share Unit Paid)
90th percentile or higher (Maximum)	200
50th percentile (Target)	100
10th percentile (Threshold)	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.

2011-2013 Payouts

Performance share grants were made in 2011 with a three-year performance period that ended on December 31, 2013. Based on the Company's total shareholder return achievement relative to that of the Philadelphia Utility Index (50% payout) and the custom peer group (10% payout), the payout percentage was 30% of target, which is the average of the two peer groups. The following table shows the target and actual awards of performance shares for the named executive officers.

	Target Performance Shares (#)	Target Value of Performance Shares ($)	Performance Shares Earned (#)	Value of Performance Shares Earned ($)
T. A. Fanning	62,468	2,246,974	18,740	770,401
A. P. Beattie	19,026	684,365	5,707	234,615
W. P. Bowers	22,278	801,340	6,683	274,738
K. S. Greene (1)	0	0	0	0
C. D. McCrary	23,410	842,058	7,023	288,716

(1) Ms. Greene was not employed by the Southern Company system when the Compensation Committee granted performance shares and, therefore, her full long-term target value for 2013 was granted in stock options.

Restricted Stock Units

In limited situations, restricted stock units are granted to address specific needs, including retention. These awards serve two primary purposes. They further align the recipient's interests with those of the Company's stockholders, and they provide strong retention value. For information on treatment upon termination or change in control, see Potential Payments Upon Termination or Change in Control after the Summary Compensation Table.

Due to benefits Ms. Greene forfeited upon leaving her former employer, the Compensation Committee granted her restricted stock units valued at $2,000,005 on the grant date. The restricted stock units will vest incrementally each year starting April 1, 2015 and ending April 1, 2018 if she remains employed with the Southern Company system. The Compensation Committee also sought advice from Pay Governance in determining market practice and the appropriate value of the award.

Restricted stock units were granted to Mr. McCrary in 2012 with a vesting date of December 31, 2014 in order to retain Mr. McCrary until his successor was named and expiration of an appropriate transition period. Mr. McCrary's successor was announced in February 2014, and Mr. McCrary is retiring effective May 1, 2014. The Compensation Committee modified the vesting date to April 30, 2014.

See the Summary Compensation Table, the Grants of Plan-Based Awards table, the Outstanding Equity Awards at 2013 Fiscal Year End table, and accompanying information for more information on these awards of restricted stock units.

Timing of Performance-Based Compensation

As discussed above, the 2013 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 by the Compensation Committee. The establishment of performance-based compensation goals and the granting of equity awards 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 2013 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 the Southern Company system 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. The Company 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.

The Company 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 the Company 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 the named executive officers, except for Mr. Fanning whose severance payment amount is three times salary plus Performance Pay Program opportunity. No excise tax gross-up would be provided. More information about severance arrangements is included in Potential Payments upon Termination or Change in Control.

Perquisites

The Company provides limited ongoing perquisites to its executive officers, including the named executive officers. The perquisites provided in 2013, including amounts, are described in detail in the information accompanying the Summary Compensation Table. No tax assistance is provided on perquisites, except on certain relocation-related benefits. Ms. Greene received relocation-related benefits and related tax assistance in 2013.

In 2013, the Compensation Committee approved payment of a country club initiation fee for Mr. Beattie in the amount of $85,000. This benefit was provided primarily for his business use, and the Company will not be responsible for any ongoing dues or other fees associated with this membership. The amount was taxable compensation to Mr. Beattie, and no tax gross-up was provided.

EXECUTIVE STOCK OWNERSHIP REQUIREMENTS

Officers of the Company and its subsidiaries 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 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 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. Mr. McCrary is over 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
T. A. Fanning	5 Times	10 Times
A. P. Beattie	3 Times	6 Times
W. P. Bowers	3 Times	6 Times
K. S. Greene	3 Times	6 Times
C. D. McCrary	1.5 Times	3 Times

Newly-elected officers, including Ms. Greene, have approximately five years from the date of their election to meet the applicable ownership requirement. Newly-promoted officers, including Messrs. Fanning and Beattie, 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 requirements.

IMPACT OF ACCOUNTING AND TAX TREATMENTS ON COMPENSATION

Section 162(m) of the Internal Revenue Code of 1986, as amended (Code), limits the tax deductibility of the compensation of the named executive officers, except Mr. Beattie, that exceeds $1 million per year unless the compensation is paid under a performance-based plan as defined in the Code that has been approved by stockholders. The Company has obtained stockholder approval of the Omnibus Incentive Compensation Plan, under which most of the performance-based compensation is paid. Because the Company's policy is to maximize long-term stockholder value, as described fully in this CD&A, tax deductibility is not the only factor considered in setting compensation. The Compensation Committee has the discretion to award compensation that may not be tax deductible.

The Compensation Committee approved a formula in February 2013 that represented a maximum annual performance-based compensation amount payable to the affected named executive officers. However, as described previously in this CD&A, the Compensation Committee later modified the methodology for calculating the business unit financial goal performance for over 4,000 Southern Company system employees, including Mr. Fanning and Ms. Greene, whose payouts exceeded the amounts calculated under the formula established in February. For Messrs. Bowers and McCrary, the Compensation Committee reduced their payments based on the results of the formula established in February 2013 to determine the actual payout amounts pursuant to the methodologies described in this CD&A.

POLICY ON RECOVERY OF AWARDS

The Company's Omnibus Incentive Compensation Plan provides that, if the Company is required to prepare an accounting restatement due to material noncompliance as a result of misconduct, and if an executive officer of the Company 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 must repay the Company 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

The Company's policy is that employees and outside Directors will not trade Company options on the options market and will not engage in short sales.

REALIZABLE PERFORMANCE-BASED COMPENSATION ANALYSIS

The SEC has promulgated rules regarding how total compensation is calculated in the Summary Compensation Table. These rules include accounting assumptions that affect the value reported for equity grants. However, as the Company's performance changes over time, the Common Stock price can fluctuate, affecting the value of equity grants made to the named executive officers. The Compensation Committee believes it is important to look at those changes to fully understand the value of the compensation received because the reported value is only realized if the Company meets certain performance criteria. In order to supplement the SEC-required disclosure, the table below compares the target or grant date value of performance-based compensation granted to Mr. Fanning in 2011, 2012, and 2013 with the value actually received or as measured on December 31, 2013.

	Performance Pay Program		Performance Shares		Stock Options	
Grant Date	Target ($)	Value Received ($)	Grant Date Value ($)	Value Received/Projected ($)	Grant Date Value ($)	Value as of December 31, 2013 ($)
2011	1,123,500	1,797,600	2,246,974	770,401[1]	1,498,000	1,447,298
2012	1,293,750	1,837,125	3,037,473	237,904 [2]	2,025,000	--[3]
2013	1,332,563	1,199,307	3,128,625	254,060 [2]	2,085,747	-- [3]

(1) The amount shown for performance shares in 2011 is the value Mr. Fanning received based on the payout of the performance shares granted in 2011 for the 2011-2013 performance period.

(2) The amounts shown for performance shares granted in 2012 and 2013 are the projected amounts based on performance levels relative to peers as of December 31, 2013. This amount is subject to change based on the Company's performance relative to its peers at the end of the applicable three-year performance period. See Performance Shares in this CD&A for a description of the Company's performance share peer group.

(3) The exercise price for the stock options granted to Mr. Fanning in both 2012 and 2013 is below the closing stock price on December 31, 2013.

COMPENSATION AND MANAGEMENT SUCCESSION 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 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, 2013 and in this Proxy Statement. The 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 2011, 2012, and 2013 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)
Thomas A. Fanning	2013	1,152,389	—	3,128,625	2,085,747	1,199,307	805,738	66,485	8,438,291
	2012	1,114,846	—	3,037,473	2,025,000	2,078,158	4,712,413	67,458	13,035,348
Chairman, President, and Chief Executive Officer	2011	1,064,399	—	2,246,974	1,498,000	2,459,181	2,423,524	62,164	9,754,242
Art P. Beattie	2013	644,039	—	796,514	531,025	437,126	402,101	122,037	2,932,842
Executive Vice	2012	615,378	—	773,330	515,558	737,382	2,747,374	34,352	5,423,374
President and Chief Financial Officer	2011	552,614	—	684,365	456,248	772,343	1,523,479	83,471	4,072,520
W. Paul Bowers	2013	760,482	—	1,031,940	687,964	498,775	—	44,375	3,023,536
	2012	739,587	42	1,003,813	669,227	1,013,366	2,024,578	50,830	5,501,443
President and Chief Executive Officer, Georgia Power	2011	715,845	—	801,340	534,225	1,232,850	1,317,429	42,052	4,643,741
Kimberly S. Greene President and Chief Executive Officer, SCS	2013	475,000	—	2,000,005	1,039,997	310,811	212,666	656,035	4,694,514
Charles D. McCrary	2013	799,124	—	1,084,347	722,922	650,630	414,103	45,396	3,716,522
	2012	777,167	—	3,054,840	703,232	1,028,204	2,437,448	44,722	8,045,613
President and Chief Executive Officer,	2011	752,219	—	842,058	561,369	1,424,219	1,733,395	44,676	5,357,936

Alabama
Power

Column (a)

Ms. Greene was not an executive officer of the Company prior to 2013.

Column (e)

This column does not reflect the value of stock awards that were actually earned or received in 2013. Rather, as required by applicable rules of the SEC, this column reports the aggregate grant date fair value of performance shares granted in 2013. 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, 2015. 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 2013 to Messrs. Fanning, Beattie, Bowers, and McCrary, assuming that the highest level of performance is achieved, is $6,257,250, $1,593,028, $2,063,880, and $2,168,694, respectively (200% of the amount shown in the table). Ms. Greene was not employed by the Southern Company system when the Compensation Committee granted performance shares in 2013; therefore, her full long-term target value for 2013 was granted in stock options. For Ms. Greene, the amount in column (e) reflects the grant date fair value ($2,000,005) of restricted stock units granted in 2013 as described in the CD&A. See Note 8 to the Financial Statements 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 granted in the applicable year. See Note 8 to the Financial Statements for a discussion of the assumptions used in calculating these amounts.

Column (g)

The amounts in this column are the payouts under the annual Performance Pay Program. The amount reported for the Performance Pay Program is for the one-year performance period that ended on December 31, 2013. The Performance Pay Program is described in detail in the CD&A.

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, 2011, 2012, and 2013. 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 the Company selected for cost purposes as of that measurement date; however, the named executive officers were assumed to remain employed at the Company or any 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, 2013, 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, 2012 and December 31, 2013 are:

- Discount rate for the Pension Plan was increased to 5.05% as of December 31, 2013 from 4.30% as of December 31, 2012, and
- Discount rate for the supplemental pension plans was increased to 4.50% as of December 31, 2013 from 3.70% as of December 31, 2012.

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.

In 2013, the pension value for Mr. Bowers decreased primarily due to the change in discount rate. Pursuant to SEC rules, the negative amount for the change in pension value was not included in the column (h) total. The actual change in pension value for Mr. Bowers was negative $144,014.

Column (i)

This column reports the following items: perquisites; tax reimbursements on certain relocation-related benefits; employer contributions in 2013 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 Code; and contributions in 2013 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 for 2013 are itemized below.

	Perquisites ($)	Tax Reimbursements ($)	ESP ($)	SBP ($)	Total ($)
T. A. Fanning	7,708	—	13,005	45,772	66,485
A. P. Beattie	90,945	—	11,251	19,841	122,037
W. P. Bowers	5,686	—	12,909	25,780	44,375
K. S. Greene	444,989	199,826	—	11,220	656,035
C. D. McCrary	6,377	—	11,269	27,750	45,396

Description of Perquisites

Personal Financial Planning is provided for most officers of the Company, including all of the named executive officers. The Company 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. The Company also provides a five-year allowance of $6,000 for estate planning and tax return preparation fees.

Relocation Benefits are provided to cover the costs associated with geographic relocation. In 2013, Ms. Greene received relocation-related benefits in the amount of $423,950 in connection with her 2013 relocation from Knoxville, Tennessee to Atlanta, Georgia. This amount was for the shipment of household goods, incidental expenses related to her move, and home sale and home repurchase assistance. Also, as provided in the Company's relocation policy, tax assistance is provided on the taxable relocation benefits. If Ms. Greene terminates within two years of her relocation, these amounts must be repaid.

Personal Use of Corporate Aircraft. The Southern Company system has aircraft that are used to facilitate business travel. All flights on these aircraft must have a business purpose, except limited personal use that is associated with business travel is permitted. The amount reported for such personal use is the incremental cost of providing the benefit, primarily fuel costs. Also, if seating is available, the 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 Ms. Greene's relocation, the Compensation Committee approved personal use of the corporate aircraft for weekly round-trip flights between Atlanta and Knoxville for the first six months following her relocation to Atlanta. The perquisite amount shown above for Ms. Greene includes $20,825 for this approved personal use of corporate aircraft.

Country Club Initiation Fee. As discussed previously in the CD&A, the Compensation Committee approved payment of a country club initiation fee for Mr. Beattie in the amount of $85,000, which is included in Mr. Beattie's perquisite amount shown above. The benefit was provided primarily for his business use, and the Company will not be responsible for any ongoing dues or other fees associated with this membership. No tax assistance was provided.

Other Miscellaneous Perquisites. The amount included reflects the full cost to the Company 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.

GRANTS OF PLAN-BASED AWARDS IN 2013

This table provides information on stock option grants made and goals established for future payouts under the performance-based compensation programs during 2013 by the Compensation Committee.

Name (a)	Grant Date (b)	Estimated Future Payouts Under Non-Equity Incentive Plan Awards			Estimated Future Payouts Under Equity Incentive Plan Awards			All Other Stock Awards: Number of Shares of Stock or Units (#) (i)	All Other Option Awards: Number of Securities Underlying Options (#) (j)	Exercise or Base Price of Option Awards ($/Sh) (k)	Grant Date Fair Value of Stock and Option Awards ($) (l)
		Threshold ($) (c)	Target ($) (d)	Maximum ($) (e)	Threshold(#) (f)	Target (#) (g)	Maximum (#) (h)				
T. A. Fanning		13,326	1,332,563	2,665,126							
	2/11/2013				773	77,250	154,500				3,128,625
	2/11/2013								714,297	44.06	2,085,747
A. P. Beattie		4,857	485,695	971,390							
	2/11/2013				197	19,667	39,334				796,514
	2/11/2013								181,858	44.06	531,025
W. P. Bowers		5,733	573,304	1,146,608							
	2/11/2013				255	25,480	50,960				1,031,940
	2/11/2013								235,604	44.06	687,964
K. S. Greene		3,453	345,345	690,690							
	4/1/2013				—	—	—				
	4/1/2013								329,113	46.74	1,039,997
	4/1/2013							42,790			2,000,005
C. D. McCrary		6,024	602,435	1,204,870							
	2/11/2013				267	26,774	53,548				1,084,347
	2/11/2013								247,576	44.06	722,922

Columns (c), (d), and (e)

These columns reflect the annual Performance Pay Program opportunity granted to the named executive officers in 2013 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 2013, 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 2013 through 2015 performance period, based on the extent to which the performance goals are achieved. Any shares not earned are forfeited. Ms. Greene was not employed by the Southern Company system at the time performance shares were awarded.

Column (i)

This column reflects the number of restricted stock units granted to Ms. Greene on the grant date as described in the CD&A.

Columns (j) and (k)

Column (j) reflects the number of stock options granted to the named executive officers in 2013, as described in the CD&A, and column (k) reflects the exercise price of the stock options, which was the closing price on the grant date.

Column (l)

This column reflects the aggregate grant date fair value of the performance shares, stock options, and restricted stock units granted in 2013. 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. For restricted stock units, the value is based on the closing price of Common Stock on the grant date. The assumptions used in calculating these amounts are discussed in Note 8 to the Financial Statements.

OUTSTANDING EQUITY AWARDS AT 2013 FISCAL YEAR-END

This table provides information pertaining to all outstanding stock options and stock awards (performance shares and restricted stock units) held by or granted to the named executive officers as of December 31, 2013.

	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 ($) (d)	Option Expiration Date (e)	Number of Shares or Units of Stock That Have Not Vested (#) (f)	Market Value of Shares or Units of Stock That Have Not Vested ($) (g)	Equity Incentive Plan Awards: Number of Unearned Shares, Units, or Other Rights That Have Not Vested (#) (h)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units, or Other Rights That Have Not Vested ($) (i)
T. A. Fanning	100,158	—	35.78	2/18/2018				
	254,302	—	31.39	2/16/2019				
	233,802	—	31.17	2/15/2020				
	307,282	153,641	37.97	2/14/2021				
	199,115	398,230	44.42	2/13/2022				
	—	714,297	44.06	2/11/2023				
							72,338	2,973,815
							77,250	3,175,748
A. P. Beattie	22,550	—	36.42	2/19/2017				
	21,779	—	35.78	2/18/2018				
	13,654	—	31.39	2/16/2019				
	93,589	46,795	37.97	2/14/2021				
	50,694	101,388	44.42	2/13/2022				
	—	181,858	44.06	2/11/2023				
							18,417	757,123
							19,667	808,510
W. P. Bowers	60,576	—	32.70	2/18/2015				
	67,517	—	33.81	2/20/2016				
	70,680	—	36.42	2/19/2017				
	85,151	—	35.78	2/18/2018				
	90,942	—	31.39	2/16/2019				
	233,477	—	31.17	2/15/2020				
	109,585	54,792	37.97	2/14/2021				
	65,804	131,608	44.42	2/13/2022				
	—	235,604	44.06	2/11/2023				
							23,906	982,776
							25,480	1,047,483

OUTSTANDING EQUITY AWARDS AT 2013 FISCAL YEAR-END (continued)

	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 ($) (d)	Option Expiration Date (e)	Number of Shares or Units of Stock That Have Not Vested (#) (f)	Market Value of Shares or Units of Stock That Have Not Vested ($) (g)	Equity Incentive Plan Awards: Number of Unearned Shares, Units, or Other Rights That Have Not Vested (#) (h)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units, or Other Rights That Have Not Vested ($) (i)
K. S. Greene	—	329,113	46.74	4/1/2023				
							—	—
					43,811	1,801,070		
C. D. McCrary	102,333	—	36.42	2/19/2017				
	99,789	—	35.78	2/18/2018				
	77,647	—	31.17	2/15/2020				
	115,153	57,576	37.97	2/14/2021				
	69,148	138,295	44.42	2/13/2022				
	—	247,576	44.06	2/11/2023				
							25,121	1,032,724
							26,774	1,100,679
					46,439	1,909,107		

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 2010 with expiration dates from 2015 through 2020 were fully vested as of December 31, 2013. The options granted in 2011, 2012, and 2013 become fully vested as shown below.

Year Option Granted	Expiration Date	Date Fully Vested
2011	February 14, 2021	February 14, 2014
2012	February 13, 2022	February 13, 2015
2013	February 11, 2023	February 11, 2016

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. Please 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)

These columns reflect the number of restricted stock units, including the deemed reinvestment of dividends, held as of December 31, 2013. The value in column (g) is based on the Common Stock closing price on December 31, 2013 ($41.11). The restricted stock units for Ms. Greene vest incrementally each year starting April 1, 2015 and ending April 1, 2018 if she remains employed with the Southern Company system. The restricted stock units for Mr. McCrary vest on April 30, 2014 if he remains employed with the Southern Company system on the vesting date. See further discussion of restricted stock in the CD&A.

Columns (h) and (i)

In accordance with SEC rules, column (h) reflects the target number of performance shares that can be earned at the end of each three-year performance period (December 31, 2014 and 2015) that were granted in 2012 and 2013, respectively.

The performance shares granted for the 2011 through 2013 performance period vested on December 31, 2013 and are shown in the Option Exercises and Stock Vested in 2013 table below. The value in column (i) is derived by multiplying the number of shares in column (h) by the Common Stock closing price on December 31, 2013 ($41.11). 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 2013

	Option Awards		Stock Awards	
Name (a)	Number of Shares Acquired on Exercise (#) (b)	Value Realized on Exercise ($) (c)	Number of Shares Acquired on Vesting (#) (d)	Value Realized on Vesting ($) (e)
T. A. Fanning	—	—	18,740	770,401
A. P. Beattie	79,080	1,074,611	5,707	234,615
W. P. Bowers	—	—	43,748	1,955,265
K. S. Greene	—	—	—	—
C. D. McCrary	—	—	7,023	288,716

Columns (b) and (c)

Column (b) reflects the number of shares acquired upon the exercise of stock options during 2013, 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 2011 through 2013 performance period that vested on December 31, 2013. 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 ($41.11).

Because Ms. Greene was not an employee of the Southern Company system when performance shares were awarded in 2011, column (d) does not reflect any vested performance shares for her.

Certain restricted stock units vested on July 27, 2013 and are reflected in column (d) for Mr. Bowers. The value of the restricted stock units as shown 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 ($45.34).

PENSION BENEFITS AT 2013 FISCAL YEAR-END

Name (a)	Plan Name (b)	Number of Years Credited Service (#) (c)	Present Value of Accumulated Benefit ($) (d)	Payments During Last Fiscal Year ($) (e)
T. A. Fanning	Pension Plan	32.0	1,015,959	—
	Supplemental Benefit Plan (Pension-Related)	32.0	9,348,613	—
	Supplemental Executive Retirement Plan	32.0	3,511,454	—
A. P. Beattie	Pension Plan	36.92	1,332,438	—
	Supplemental Benefit Plan (Pension-Related)	36.92	4,505,487	—
	Supplemental Executive Retirement Plan	36.92	1,720,295	—
W. P. Bowers	Pension Plan	33.67	1,082,996	—
	Supplemental Benefit Plan (Pension-Related)	33.67	4,871,361	—
	Supplemental Executive Retirement Plan	33.67	1,518,807	—
K. S. Greene	Pension Plan	6.17	116,214	—
	Supplemental Benefit Plan (Pension-Related)	6.17	50,685	—
	Supplemental Executive Retirement Plan	6.17	158,385	—
C. D. McCrary	Pension Plan	39.0	1,609,199	—
	Supplemental Benefit Plan (Pension-Related)	39.0	8,070,928	—
	Supplemental Executive Retirement Plan	39.0	2,539,209	—

Pension Plan

The Pension Plan is a tax-qualified, funded plan. It is the Company's primary retirement plan. Generally, all full-time Southern Company system 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 rates of pay considered for this formula are the base salary rates with no adjustments for voluntary deferrals after 2008. A statutory limit restricts the amount considered each year; the limit for 2013 was $255,000.

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 salary rates.

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, 2013, all of the named executive officers are retirement-eligible except Ms. Greene.

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. As of December 31, 2013, all of the named executive officers are vested in their Pension Plan benefits. Ms. Greene received years of credited service for her previous employment with the Southern Company system. 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 Pension 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 a 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 a 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 under Potential Payments upon Termination or Change in Control.

Pension Benefit Assumptions

The following assumptions were used in the present value calculations for all pension benefits:

- Discount rate - 5.05% Pension Plan and 4.50% supplemental plans as of December 31, 2013,
- 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: 75% single life annuity; 15% level income annuity; 5% joint and 50% survivor annuity; and 5% 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, and
- Installment determination - 3.75% discount rate for single sum calculation and 4.25% prime rate during installment payment period.

For all of the named executive officers, the number of years of credited service is one year less than the number of years of employment. The number of years of credited service for Ms. Greene reflects her previous employment with the Southern Company system.

NONQUALIFIED DEFERRED COMPENSATION AS OF 2013 FISCAL YEAR-END

Name (a)	Executive Contributions in Last FY ($) (b)	Employer Contributions in Last FY ($) (c)	Aggregate Earnings in Last FY ($) (d)	Aggregate Withdrawals/ Distributions ($) (e)	Aggregate Balance at Last FYE ($) (f)
T. A. Fanning	323,178	45,772	54,119	—	2,735,819
A. P. Beattie	—	19,841	10,634	—	480,024
W. P. Bowers	444,523	25,780	39,127	—	3,683,582
K. S. Greene	—	11,220	39	—	11,259
C. D. McCrary	—	27,750	28,918	—	1,598,579

The 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 Company stockholder. During 2013, the rate of return in the Stock Equivalent Account was 0.65%.

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 2013 in the Prime Equivalent Account was 3.25%.

Column (b)

This column reports the actual amounts of compensation deferred under the DCP by each named executive officer in 2013. 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 2013 were the amounts that were earned as of December 31, 2012 but were not payable until the first quarter of 2013. These amounts are not reflected in the Summary Compensation Table because that table reports performance-based compensation that was earned in 2013 but not payable until early 2014. 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. The following chart shows the amounts previously reported.

	Amounts Deferred under the DCP prior to 2013 and previously reported ($)	Employer Contributions under the SBP prior to 2013 and previously reported ($)	Total ($)
T. A. Fanning	1,612,979	323,128	1,936,107
A. P. Beattie	34,781	41,473	76,254
W. P. Bowers	1,536,730	117,512	1,654,242
K. S. Greene	0	0	0
C. D. McCrary	489,924	348,470	838,394

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, 2013 and assumes that the price of Common Stock is the closing market price on December 31, 2013.

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 the Company'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 Company or the subsidiary company level:

- Company Change-in-Control I - Consummation of an acquisition by another entity of 20% or more of Common Stock or, following consummation of a merger with another entity, the Company's stockholders own 65% or less of the entity surviving the merger.
- Company Change-in-Control II - Consummation of an acquisition by another entity of 35% or more of Common Stock or, following consummation of a merger with another entity, the Company's stockholders own less than 50% of the Company surviving the merger.
- Company Termination - Consummation of a merger or other event and the Company is not the surviving company or Common Stock is no longer publicly traded.
- Subsidiary Company Change in Control - Consummation of an acquisition by another entity, other than another subsidiary of the Company, of 50% or more of the stock of any of the Company's subsidiaries, consummation of a merger with another entity and the Company's subsidiary is not the surviving company, or the sale of substantially all the assets of any of the Company's subsidiaries.

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 as 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.
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.
Restricted Stock Units	Forfeit.	Vest.	Forfeit.	Vest.	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 the benefit administration committee's discretion.	Same as Retirement.
SBP - 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.

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The following chart 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.

Program	Company Change-in-Control I	Company Change-in-Control II	Company Termination or Subsidiary Company 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 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 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.
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.
RSUs	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.

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Program	Company Change-in-Control I	Company Change-in-Control II	Company Termination or Subsidiary Company Change in Control	Involuntary Change-in-Control-Related Termination or Voluntary Change-in-Control-Related Termination for Good Reason
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.
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.	Two or three 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, 2013.

Pension Benefits

The amounts that would have become payable to the named executive officers if the Traditional Termination Events occurred as of December 31, 2013 under the Pension Plan, the SBP-P, and the SERP are itemized in the following chart. The amounts shown under the Retirement column are amounts that would have become payable to the named executive officers that were retirement-eligible on December 31, 2013 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 Resignation or Involuntary Termination column are the amounts that would have become payable to the named executive officers who were not retirement-eligible on December 31, 2013 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 benefit 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.

Greene was not retirement-eligible as of December 31, 2013.

		Retirement ($)	Resignation or Involuntary Termination	Death (payments to a spouse) ($)
	Pension	7,441	treated as retiring	4,763
T. A. Fanning	SBP-P	1,293,088	treated as retiring	1,293,088
	SERP	485,700	treated as retiring	485,700
	Pension	9,780	treated as retiring	5,488
A. P. Beattie	SBP-P	588,112	treated as retiring	588,112
	SERP	224,554	treated as retiring	224,554
	Pension	7,935	treated as retiring	5,015
W. P. Bowers	SBP-P	670,618	treated as retiring	670,618
	SERP	209,087	treated as retiring	209,087
	Pension	—	506	831
K. S. Greene	SBP-P	—	74,693	7,979
	SERP	—	—	24,932
	Pension	11,677	treated as retiring	5,871
C. D. McCrary	SBP-P	980,448	treated as retiring	980,448
	SERP	308,460	treated as retiring	308,460

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, 2013 following a change-in-control-related event, other than a 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.

	SBP-P ($)	SERP ($)	Total ($)
T. A. Fanning	12,930,882	4,856,998	17,787,880
A. P. Beattie	5,881,123	2,245,544	8,126,667
W. P. Bowers	6,706,181	2,090,872	8,797,053
K. S. Greene	73,466	229,574	303,040
C. D. McCrary	9,804,476	3,084,603	12,889,079

The pension benefit amounts in the tables above were calculated as of December 31, 2013 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 2.88% discount rate.

Annual Performance Pay Program

The amount payable if a change in control had occurred on December 31, 2013 is the greater of target or actual performance. Because actual payouts for 2013 performance were below the target level for all of the named executive officers except Mr. McCrary, the amount that would have been payable was the target amount as reported in the

CD&A. Mr. McCrary's actual payout was above the target level established; thus the amount that would have been payable was the actual amount paid as reported in the Summary Compensation Table.

Stock Options, Performance Shares, and Restricted Stock 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, the value is the excess of the exercise price and the closing price of Common Stock on December 31, 2013. The value of performance shares and restricted stock units is calculated using the closing price of Common Stock on December 31, 2013. 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 and restricted stock units 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 ($)
	Stock Options	Performance Shares	Restricted Stock Units	Stock Options	Performance Shares	Restricted Stock Units	
T. A. Fanning	1,266,168	149,588	—	2,360,827	149,588	—	12,926,510
A. P. Beattie	148,183	38,084	—	350,449	38,084	—	2,360,997
W. P. Bowers	422,004	49,386	—	1,205,736	49,386	—	7,538,782
K. S. Greene	329,113	—	43,811	329,113	—	43,811	1,801,070
C. D. McCrary	443,447	51,895	46,439	907,517	51,895	46,439	6,368,508

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

All of the named executive officers, except Ms. Greene, are retirement-eligible. Healthcare benefits are provided to retirees, and there is no incremental payment associated with the termination or change-in-control events, 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 for up to a maximum of three years for Ms. Greene is $54,378.

Financial Planning Perquisite

An additional year of the financial planning perquisite, which is set at a maximum of $8,700 per year, will be provided after retirement for retirement-eligible named executive officers.

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 she or he 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 three times the base salary and target payout under the annual Performance Pay Program for Mr.

Fanning and two times the base salary and target payout under the annual Performance Pay Program for the other named executive officers. If any portion of the severance amount constitutes an "excess parachute payment" under Section 280G of the Code and is therefore subject to an excise tax, the severance amount will be reduced unless the after-tax "unreduced amount" exceeds the after-tax "reduced amount." Excise tax gross-ups will not be provided on change-in-control severance payments.

The table below estimates the severance payments that would be made to the named executive officers if they were terminated as of December 31, 2013 in connection with a change in control.

	Severance Amount ($)
T. A. Fanning	7,473,938
A. P. Beattie	2,266,579
W. P. Bowers	2,675,420
K. S. Greene	2,210,000
C. D. McCrary	2,811,365

Compensation Risk Assessment

The Company reviewed its compensation policies and practices and concluded that excessive risk-taking is not encouraged. This conclusion was based on an assessment of the mix of pay components and performance goals, the annual pay/performance analysis by the Compensation Committee's independent consultant, stock ownership requirements, compensation governance practices, and the claw-back provision. The assessment was reviewed with the Compensation Committee.

Compensation Committee Interlocks and Insider Participation

The Compensation Committee is made up of independent Directors of the Company who have never served as executive officers of the Company. During 2013, none of the Company's executive officers served on the Board of Directors of any entities whose executive officers serve on the Compensation Committee.

Other Information

SECTION 16(a) BENEFICIAL OWNERSHIP REPORTING COMPLIANCE

No reporting person of the Company failed to file, on a timely basis, the reports required by Section 16(a) of the Securities Exchange Act of 1934, as amended, except for an inadvertent late filing of a Form 4 by Mr. Mark A. Crosswhite.

CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Mr. Donald M. James is the Chief Executive Officer of Vulcan Materials Company. During 2013, subsidiaries of the Company purchased approximately $4,370,222 of goods and services from Vulcan Materials Company and its affiliates, primarily related to on-going construction projects.

Mr. E. Jenner Wood III, a Director of the Company, is Chairman, President, and Chief Executive Officer of the Atlanta Division of SunTrust Bank and Executive Vice President of SunTrust Banks, Inc. During 2013, subsidiaries of the Company made payments of approximately $1,501,400 to certain subsidiaries of SunTrust Banks, Inc., substantially related to aircraft leases.

During 2013, certain subsidiaries of SunTrust Banks, Inc. also furnished a number of regular banking services in the ordinary course of business to the Company and its subsidiaries and served as an underwriter for certain securities offerings of the Company and its subsidiaries for which $931,913 was received by these certain subsidiaries of SunTrust Banks, Inc. The Company and its subsidiaries intend to maintain normal banking relations with SunTrust Banks, Inc. and its subsidiaries in the future.

The Company does not have a written policy pertaining solely to the approval or ratification of "related party transactions." The Company has a Code of Ethics as well as a Contract 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.

APPENDIX A

POLICY ON ENGAGEMENT OF THE INDEPENDENT AUDITOR
FOR AUDIT AND NON-AUDIT SERVICES

A. Southern Company (including its subsidiaries) will not engage the independent auditor to perform any services that are prohibited by the Sarbanes-Oxley Act of 2002. It shall further be the policy of the Company not to retain the independent auditor for non-audit services unless there is a compelling reason to do so and such retention is otherwise pre-approved consistent with this policy. Non-audit services that are prohibited include:

1. Bookkeeping and other services related to the preparation of accounting records or financial statements of the Company or its subsidiaries.
2. Financial information systems design and implementation.
3. Appraisal or valuation services, fairness opinions, or contribution-in-kind reports.
4. Actuarial services.
5. Internal audit outsourcing services.
6. Management functions or human resources.
7. Broker or dealer, investment adviser, or investment banking services.
8. Legal services or expert services unrelated to financial statement audits.
9. Any other service that the Public Company Accounting Oversight Board determines, by regulation, is impermissible.

B. Effective January 1, 2003, officers of the Company (including its subsidiaries) may not engage the independent auditor to perform any personal services, such as personal financial planning or personal income tax services.

C. All audit services (including providing comfort letters and consents in connection with securities issuances) and permissible non-audit services provided by the independent auditor must be pre-approved by the Southern Company Audit Committee.

D. Under this Policy, the Audit Committee's approval of the independent auditor's annual arrangements letter shall constitute pre-approval for all services covered in the letter.

E. By adopting this Policy, the Audit Committee hereby pre-approves the engagement of the independent auditor to provide services related to the issuance of comfort letters and consents required for securities sales by the Company and its subsidiaries and services related to consultation on routine accounting and tax matters. The actual amounts expended for such services each calendar quarter shall be reported to the Committee at a subsequent Committee meeting.

F. The Audit Committee also delegates to its Chairman the authority to grant pre-approvals for the engagement of the independent auditor to provide any permissible service up to a limit of $50,000 per engagement. Any engagements pre-approved by the Chairman shall be presented to the full Committee at its next scheduled regular meeting.

G. The Southern Company Comptroller shall establish processes and procedures to carry out this Policy.

Approved by the Southern Company Audit Committee
December 9, 2002

APPENDIX B

2013 ANNUAL REPORT

SOUTHERN COMPANY COMMON STOCK AND DIVIDEND INFORMATION

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	Dividend
2013			
First Quarter	$46.95	$42.82	$0.4900
Second Quarter	48.74	42.32	0.5075
Third Quarter	45.75	40.63	0.5075
Fourth Quarter	42.94	40.03	0.5075
2012			
First Quarter	$46.06	$43.71	$0.4725
Second Quarter	48.45	44.22	0.4900
Third Quarter	48.59	44.64	0.4900
Fourth Quarter	47.09	41.75	0.4900

On March 31, 2014, Southern Company had 142,385 registered stockholders.

FIVE-YEAR CUMULATIVE PERFORMANCE GRAPH

This performance graph compares the cumulative total shareholder return on the Company's common stock with the Standard & Poor's Electric Utility Index and the Standard & Poor's 500 index for the past five years. The graph assumes that $100 was invested on December 31, 2008 in the Company's common stock and each of the above indices and that all dividends were reinvested. The stockholder return shown below for the five-year historical period may not be indicative of future performance.

TWENTY-YEAR CUMULATIVE PERFORMANCE GRAPH

This performance graph compares the cumulative total shareholder return on the Company's common stock with the Standard & Poor's Electric Utility Index and the Standard & Poor's 500 index for the past 20 years. The graph assumes that $100 was invested on December 31, 1993 in the Company's common stock and each of the above indices and that all dividends were reinvested. The distribution of shares of Mirant Corporation stock to the Company's stockholders in 2001 is treated as a special dividend for purposes of calculating the Company's shareholder return. The stockholder return shown below for the twenty-year historical period may not be indicative of future performance.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Southern Company and Subsidiary Companies 2013 Annual Report
The management of The Southern Company (Southern Company) is responsible for establishing and maintaining an adequate system of internal control over financial reporting as required by the Sarbanes-Oxley Act of 2002 and as defined in Exchange Act Rule 13a-15(f). A control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met.
Under management's supervision, an evaluation of the design and effectiveness of Southern Company's internal control over financial reporting was conducted based on the framework in Internal Control—Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that Southern Company's internal control over financial reporting was effective as of December 31, 2013.
Deloitte & Touche LLP, an independent registered public accounting firm, as auditors of Southern Company's financial statements, has issued an attestation report on the effectiveness of Southern Company's internal control over financial reporting as of December 31, 2013. Deloitte & Touche LLP's report on Southern Company's internal control over financial reporting is included herein.

/s/ Thomas A. Fanning

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

/s/ Art P. Beattie

Art P. Beattie
Executive Vice President and Chief Financial Officer
February 27, 2014

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM
To the Board of Directors and Stockholders of
The Southern Company

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of The Southern Company and Subsidiary Companies (the Company) as of December 31, 2013 and 2012, and the related consolidated statements of income, comprehensive income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2013. We also have audited the Company's internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control - Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting (page B-1). 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 B-38 to B-105) referred to above present fairly, in all material respects, the financial position of Southern Company and Subsidiary Companies as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on the criteria established in Internal Control - Integrated Framework

(1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ Deloitte & Touche LLP

Atlanta, Georgia
February 27, 2014

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

OVERVIEW

Business Activities

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

Many factors affect the opportunities, challenges, and risks of the Southern Company system's electricity business. These factors include the traditional operating companies' ability to maintain a constructive regulatory environment, to maintain and grow energy sales given economic conditions, and to effectively manage and secure timely recovery of costs. These costs include those related to projected long-term demand growth, increasingly stringent environmental standards, reliability, fuel, capital expenditures, including new plants, and restoration following major storms. Subsidiaries of Southern Company are constructing two new nuclear generating units at Plant Vogtle (Plant Vogtle Units 3 and 4) (45.7% ownership interest by Georgia Power in two units, each with approximately 1,100 megawatts (MWs)) and the 582-MW integrated coal gasification combined cycle facility under construction in Kemper County, Mississippi (Kemper IGCC) (in which Mississippi Power is ultimately expected to hold an 85% ownership interest). Each of the traditional operating companies has various regulatory mechanisms that operate to address cost recovery. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Southern Company system for the foreseeable future. In 2013, each of the traditional operating companies completed significant rate proceedings. See Note 3 to the financial statements under "Retail Regulatory Matters" and "Integrated Coal Gasification Combined Cycle" for additional information.

Another major factor is the profitability of the competitive market-based wholesale generating business. Southern Power continues to execute its strategy through a combination of acquiring, constructing, and selling power plants, including renewable energy projects, and by entering into power purchase agreements (PPAs) primarily with investor-owned utilities, independent power producers, municipalities, and electric cooperatives.

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

Key Performance Indicators

In striving to achieve superior risk-adjusted returns while providing cost-effective energy to more than four million customers, the Southern Company system continues to focus on several key performance indicators. These indicators include customer satisfaction, plant availability, system reliability, execution of major construction projects, and earnings per share (EPS). Southern Company's financial success is directly tied to customer satisfaction. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys and reliability indicators to evaluate the results of the Southern Company system.

Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of fossil/hydro plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. The fossil/hydro 2013 Peak Season EFOR was slightly better than the target; however, see FUTURE EARNINGS POTENTIAL – "Other Matters" herein for information regarding an explosion at Plant Bowen in April 2013 that negatively impacted the fossil/hydro 2013 Peak

Season EFOR. Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on historical performance. The performance for 2013 was better than the target for these reliability measures. Primarily as a result of charges for estimated probable losses related to construction of the Kemper IGCC, Southern Company's EPS for 2013 did not meet the target on a generally accepted accounting principles (GAAP) basis. See RESULTS OF OPERATIONS – "Estimated Loss on Kemper IGCC" and Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information.

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

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

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

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

Does not reflect EPS as calculated in accordance with GAAP. Southern Company management uses the non-GAAP measure of EPS, excluding items described above, to evaluate the performance of Southern Company's ongoing business activities. Southern Company believes the presentation of this non-GAAP measure of earnings is useful for investors because it provides earnings information that is consistent with the historical and ongoing business activities of the Company. The presentation of this information is not meant to be considered a substitute for financial measures prepared in accordance with GAAP.
See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance.

Earnings

Southern Company's net income after dividends on preferred and preference stock of subsidiaries was $1.6 billion in 2013, a decrease of $706 million, or 30.0%, from the prior year. The decrease was primarily the result of $1.2 billion in pre-tax charges ($729 million after-tax) for revisions of estimated costs expected to be incurred on Mississippi Power's construction of the Kemper IGCC above the $2.88 billion cost cap established by the Mississippi Public Service Commission (PSC), net of $245 million of grants awarded to the project by the U.S. Department of Energy (DOE) under the Clean Coal Power Initiative Round 2 (DOE Grants) and excluding the cost of the lignite mine and equipment, the cost of the carbon dioxide (CO_2) pipeline facilities, allowance for funds used during construction (AFUDC), and certain general exceptions, including change of law, force majeure, and beneficial capital (which exists when Mississippi Power demonstrates that the purpose and effect of the construction cost increase is to produce efficiencies that will result in a neutral or favorable effect on customers relative to the original proposal for the certificate of public convenience and necessity (CPCN)) (Cost Cap Exceptions). Also contributing to the decrease in net income were increases in depreciation and amortization and other operations and maintenance expenses, partially offset by increases in retail revenues and AFUDC.

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

Basic EPS was $1.88 in 2013, $2.70 in 2012, and $2.57 in 2011. Diluted EPS, which factors in additional shares related to stock-based compensation, was $1.87 in 2013, $2.67 in 2012, and $2.55 in 2011. EPS for 2013 was negatively impacted by $0.02 per share as a result of an increase in the average shares outstanding. See FINANCIAL CONDITION AND LIQUIDITY – "Financing Activities" herein for additional information.

Dividends

Southern Company has paid dividends on its common stock since 1948. Dividends paid per share of common stock were $2.0125 in 2013, $1.9425 in 2012, and $1.8725 in 2011. In January 2014, Southern Company declared a quarterly dividend of 50.75 cents per share. This is the 265th consecutive quarter that Southern Company has paid a dividend equal to or higher than the previous quarter. For 2013, the actual payout ratio was 107%, while the payout ratio of net income excluding charges for estimated probable losses relating to Mississippi Power's construction of the Kemper IGCC and the restructuring of a leveraged lease investment as well as proceeds from the MC Asset Recovery insurance settlement was 74%.

RESULTS OF OPERATIONS

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

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

Electricity Business

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

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

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

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

Retail revenues increased $354 million, or 2.5%, in 2013 as compared to the prior year. The significant factors driving this change are shown in the preceding table. The increase in rates and pricing in 2013 was primarily due to base tariff increases at Georgia Power effective April 1, 2012 and January 1, 2013, as approved by the Georgia PSC, related to placing new generating units at Plant McDonough-Atkinson in service and collecting financing costs related to the construction of Plant Vogtle Units 3 and 4 through the Nuclear Construction Cost Recovery (NCCR) tariff, as well as higher contributions from market-driven rates from commercial and industrial customers.
Retail revenues decreased $884 million, or 5.9%, in 2012 as compared to the prior year. The significant factors driving this change are shown in the preceding table. The increase in rates and pricing in 2012 was primarily due to increases in retail revenues at Georgia Power due to base tariff increases effective April 1, 2012 related to placing Plant McDonough-Atkinson Units 4 and 5 in service, collecting financing costs related to the construction of Plant Vogtle Units 3 and 4 through the NCCR tariff, and demand-side management programs effective January 1, 2012, as approved by the Georgia PSC, as well as the rate pricing effect of decreased customer usage. Also contributing to the increase were the elimination of a tax-related adjustment under Alabama Power's rate structure that was effective with October 2011 billings and higher revenues due to increases in retail base rates at Gulf Power. These increases were partially offset by lower contributions from market-driven rates from commercial and industrial customers at Georgia Power and decreased revenues under rate certificated new plant environmental (Rate CNP Environmental) at Alabama Power.
See FUTURE EARNINGS POTENTIAL – "PSC Matters – Alabama Power – Retail Rate Adjustments" and "PSC Matters – Georgia Power – Rate Plans" herein for additional information. Also see "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales growth (decline) and weather.
Electric rates for the traditional operating companies include provisions to adjust billings for fluctuations in fuel costs, including the energy component of purchased power costs. Under these provisions, fuel revenues generally equal fuel expenses, including the energy component of purchased power costs, and do not affect net income. The traditional operating companies may also have one or more regulatory mechanisms to recover other costs such as environmental, storm damage, new plants, and PPAs.
Wholesale revenues consist of PPAs with investor-owned utilities and electric cooperatives and short-term opportunity sales. Wholesale revenues from PPAs have both capacity and energy components. Capacity revenues reflect the recovery of fixed costs and a return on investment. Energy revenues will vary depending on fuel prices, the

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

Wholesale revenues from power sales were as follows:

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

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

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

Other Electric Revenues

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

Energy Sales

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

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

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

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

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

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

Fuel and Purchased Power Expenses

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

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

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

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

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

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

Fuel and purchased power energy transactions at the traditional operating companies are generally offset by fuel revenues and do not have a significant impact on net income. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Retail Fuel Cost Recovery" herein for additional information. Fuel expenses incurred under Southern Power's PPAs are generally the responsibility of the counterparties and do not significantly impact net income.

Fuel

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

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

Purchased Power

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

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

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

Other Operations and Maintenance Expenses

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

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

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

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

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

Depreciation and Amortization

Depreciation and amortization increased $114 million, or 6.4%, in 2013 as compared to the prior year primarily due to additional plant in service related to the completion of Georgia Power's Plant McDonough-Atkinson Units 5 and 6 in April 2012 and October 2012, respectively, and six Southern Power plants between June 2012 and October 2013, certain coal unit retirement decisions (with respect to the portion of such units dedicated to wholesale service) at Georgia Power, and additional transmission and distribution projects. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Georgia Power – Integrated Resource Plan" for additional information on Georgia Power's unit retirement decisions. These increases were partially offset by a net reduction in amortization primarily related to amortization of a regulatory liability for state income tax credits at Georgia Power and by the deferral of certain expenses under an accounting order at Alabama Power. See Note 1 to the financial statements under "Regulatory Assets and Liabilities" for additional information on the state income tax credits regulatory liability. Also see FUTURE EARNINGS POTENTIAL – "PSC Matters – Alabama Power – Compliance and Pension Cost Accounting Order" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Alabama Power – Compliance and Pension Cost Accounting Order" for additional information on Alabama Power's accounting order.

Depreciation and amortization increased $72 million, or 4.2%, in 2012 as compared to the prior year primarily as a result of additional plant in service related to new generation at Georgia Power's Plant McDonough-Atkinson Units 4 and 5, additional plant in service at Southern Power, as well as transmission, distribution, and environmental projects, partially offset by amortization of a regulatory liability for state income tax credits at Georgia Power as authorized by the Georgia PSC.

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

Taxes Other Than Income Taxes

Taxes other than income taxes increased $20 million, or 2.2%, in 2013 as compared to the prior year primarily due to increases in property taxes. Taxes other than income taxes increased $13 million, or 1.4%, in 2012 as compared to the prior year primarily due to increases in property taxes, partially offset by a decrease in municipal franchise fees, which are based on revenues from energy sales.

Estimated Loss on Kemper IGCC

In 2013, estimated probable losses on the Kemper IGCC of $1.2 billion were recorded at Southern Company to reflect revisions of estimated costs expected to be incurred on Mississippi Power's construction of the Kemper IGCC in excess of the $2.88 billion cost cap established by the Mississippi PSC, net of the DOE Grants and excluding the Cost Cap Exceptions. See FUTURE EARNINGS POTENTIAL – "Construction Program" herein and Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information.

Allowance for Equity Funds Used During Construction

AFUDC equity increased $47 million, or 32.9%, in 2013 as compared to the prior year primarily due to an increase in construction work in progress (CWIP) related to the construction of Mississippi Power's Kemper IGCC and increased capital expenditures at Alabama Power, partially offset by the completion of Georgia Power's Plant McDonough-Atkinson Units 5 and 6 in 2012. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information regarding the Kemper IGCC.

AFUDC equity decreased $10 million, or 6.5%, in 2012 as compared to the prior year primarily due to the completion of Georgia Power's Plant McDonough-Atkinson Units 4, 5, and 6 in December 2011, April 2012, and October 2012, respectively, partially offset by increases in CWIP related to the construction of Mississippi Power's Kemper IGCC.

Interest Expense, Net of Amounts Capitalized

Total interest charges and other financing costs decreased $32 million, or 3.9%, in 2013 as compared to the prior year primarily due to lower interest rates, the timing of issuances and redemptions of long-term debt, an increase in capitalized interest primarily resulting from AFUDC debt associated with Mississippi Power's Kemper IGCC, and an increase in capitalized interest associated with the construction of Southern Power's Plants Campo Verde and Spectrum. These decreases were partially offset by a decrease in capitalized interest resulting from the completion of Southern Power's Plants Nacogdoches and Cleveland, a reduction in AFUDC debt due to the completion of Georgia Power's Plant McDonough-Atkinson Units 5 and 6, and the conclusion of certain state and federal tax audits in 2012.

Total interest charges and other financing costs increased $17 million, or 2.1%, in 2012 as compared to the prior year primarily due to a $23 million reduction in interest expense in 2011 at Georgia Power resulting from the settlement of litigation with the Georgia Department of Revenue, a decrease in AFUDC debt at Georgia Power due to the completion of Plant McDonough-Atkinson Units 4 and 5, and a net increase in interest expense related to senior notes and other long-term debt. The increases were partially offset by a decrease in interest expense on existing variable rate pollution control revenue bonds, an increase in capitalized interest primarily resulting from AFUDC debt associated with the Kemper IGCC at Mississippi Power, and a decrease related to the conclusion of certain state and federal income tax audits.

Other Income (Expense), Net

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

Income Taxes

Income taxes decreased $465 million, or 33.2%, in 2013 as compared to the prior year primarily due to lower pre-tax earnings, an increase in tax benefits recognized from investment tax credits at Southern Power, and a net increase in non-taxable AFUDC equity, partially offset by a decrease in state income tax credits, primarily at Georgia Power.

Income taxes increased $107 million, or 8.3%, in 2012 as compared to the prior year primarily due to higher pre-tax earnings, an increase in non-deductible book depreciation, and a decrease in non-taxable AFUDC equity, partially offset by state income tax credits.

Other Business Activities

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

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

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

Operating Revenues

Southern Company's non-electric operating revenues from these other business activities decreased $7 million, or 11.9%, and $11 million, or 15.7%, in 2013 and 2012, respectively, as compared to the prior years. The decreases were primarily the result of decreases in revenues at SouthernLINC Wireless related to lower average per subscriber revenue and fewer subscribers due to continued competition in the industry.

Other Operations and Maintenance Expenses

Other operations and maintenance expenses for these other businesses decreased $9 million, or 11.7%, and $19 million, or 19.8%, in 2013 and 2012, respectively, as compared to the prior years. The decrease in 2013 was primarily related to lower operating expenses at SouthernLINC Wireless and decreases in consulting and legal fees, partially offset by higher operating expenses at Southern Holdings and a decrease in the amount of insurance proceeds received in 2013 related to the litigation settlement with MC Asset Recovery, LLC as compared to the amount received in 2012. The decrease in 2012 was primarily related to the insurance proceeds received in 2012. See Note 3 to the financial statements under "Insurance Recovery" for additional information.

Interest Income

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

Other Income (Expense), Net

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

Southern Company has several leveraged lease agreements which relate to international and domestic energy generation, distribution, and transportation assets. Southern Company receives federal income tax deductions for depreciation and amortization, as well as interest on long-term debt related to these investments. See Note 1 under "Leveraged Leases" for additional information.

Interest Expense

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

Income Taxes

Income taxes for these other businesses decreased $20 million, or 30.3%, in 2013 as compared to the prior year primarily as a result of higher pre-tax losses. Income taxes for these other businesses increased $8 million, or 10.8%, in 2012 as compared to the prior year primarily as a result of lower pre-tax losses.

Effects of Inflation

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

FUTURE EARNINGS POTENTIAL

General

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

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

As part of its ongoing effort to adapt to changing market conditions, Southern Company continues to evaluate and consider a wide array of potential business strategies. These strategies may include business combinations, partnerships, and acquisitions involving other utility or non-utility businesses or properties, disposition of certain assets, internal restructuring, or some combination thereof. Furthermore, Southern Company may engage in new business ventures that arise from competitive and regulatory changes in the utility industry. Pursuit of any of the above strategies, or any combination thereof, may significantly affect the business operations, risks, and financial condition of Southern Company.

Environmental Matters

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

New Source Review Actions

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

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

Environmental Statutes and Regulations

General

The electric utilities' operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; the Endangered Species Act; and related federal and state regulations. Compliance with these environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. Through 2013, the traditional operating companies had invested approximately $9.4 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $712 million, $340 million, and $300 million for 2013, 2012, and 2011, respectively. The Southern Company system expects that capital expenditures to comply with environmental statutes and regulations will total approximately $3.2 billion from 2014 through 2016, with annual totals of approximately $1.5 billion, $1.1 billion, and $600 million for 2014, 2015, and 2016, respectively.

The Southern Company system continues to monitor the development of the EPA's proposed water and coal combustion residuals rules and to evaluate compliance options. Based on its preliminary analysis and an assumption that coal combustion residuals will continue to be regulated as non-hazardous solid waste under the proposed rule, the Southern Company system does not anticipate that material compliance costs with respect to these proposed rules will be required during the period of 2014 through 2016. The ultimate capital expenditures and compliance costs with respect to these proposed rules, including additional expenditures required after 2016, will be dependent on the requirements of the final rules and regulations adopted by the EPA and the outcome of any legal challenges to these rules. See "Water Quality" and "Coal Combustion Residuals" herein for additional information.

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

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

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

Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Southern Company system. Since 1990, the electric utilities have spent approximately $8.0 billion in reducing and monitoring emissions pursuant to the Clean Air Act. Additional controls are currently planned or under consideration to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements.

The EPA regulates ground level ozone concentrations through implementation of an eight-hour ozone National Ambient Air Quality Standard (NAAQS). In 2008, the EPA adopted a more stringent eight-hour ozone NAAQS, which it began to implement in 2011. In May 2012, the EPA published its final determination of nonattainment areas based on the 2008 eight-hour ozone NAAQS. The only area within the traditional operating companies' service territory designated as a nonattainment area is a 15-county area within metropolitan Atlanta.

The EPA regulates fine particulate matter concentrations on an annual and 24-hour average basis. All areas within the traditional operating companies' service territory have achieved attainment with the 1997 and 2006 particulate matter NAAQS, and the EPA has officially redesignated some former nonattainment areas within the service territory as attainment for these standards. Redesignation requests for certain areas designated as nonattainment in Georgia are still pending with the EPA. On January 15, 2013, the EPA published a final rule that increases the stringency of the annual fine particulate matter standard. The new standard could result in the designation of new nonattainment areas within the traditional operating companies' service territories.

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

On February 13, 2014, the EPA proposed to delete from the Alabama State Implementation Plan (SIP) the Alabama opacity rule that the EPA approved in 2008, which provides operational flexibility to affected units. On March 6, 2013, the U.S. Court of Appeals for the Eleventh Circuit ruled in favor of Alabama Power and vacated an earlier attempt by the EPA to rescind its 2008 approval. The EPA's latest proposal characterizes the proposed deletion as an error correction within the meaning of the Clean Air Act. Alabama Power believes this interpretation of the Clean Air

Act to be incorrect. If finalized, this proposed action could affect unit availability and result in increased operations and maintenance costs for affected units, including units owned by Alabama Power, units co-owned by Mississippi Power, and units owned by SEGCO.

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

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

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

In February 2012, the EPA finalized the Mercury and Air Toxics Standards (MATS) rule, which imposes stringent emissions limits for acid gases, mercury, and particulate matter on coal- and oil-fired electric utility steam generating units. Compliance for existing sources is required by April 16, 2015; however, states may authorize a compliance extension of up to one year to April 16, 2016. Compliance extensions have been granted for some of the affected units owned or operated by the traditional operating companies.

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

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

The Southern Company system has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the current and proposed environmental requirements discussed above. The impacts of the eight-hour ozone, fine particulate matter and SO_2 NAAQS, the Alabama opacity rule, CAIR and any future replacement rule, CAVR, the MATS rule, the NSPS for CTs, and the SSM rule on the Southern Company system cannot be determined at this time and will depend on the specific provisions of recently finalized and future rules, the resolution of pending and future legal challenges, and the development and implementation of rules at the state level. These regulations could result in significant additional compliance costs that could affect future unit retirement and replacement decisions and results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

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

Water Quality

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

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

The impact of these proposed rules cannot be determined at this time and will depend on the specific provisions of the final rules and the outcome of any legal challenges. These regulations could result in significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. Also, results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates or through PPAs. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

Coal Combustion Residuals

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

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

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

Environmental Remediation

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

Global Climate Issues

The EPA currently regulates greenhouse gases under the Prevention of Significant Deterioration and Title V operating permit programs of the Clean Air Act. The legal basis for these regulations is currently being challenged in the U.S. Supreme Court. In addition, over the past several years, the U.S. Congress has considered many proposals to reduce greenhouse gas emissions, mandate renewable or clean energy, and impose energy efficiency standards. Such proposals are expected to continue to be considered by the U.S. Congress. International climate change negotiations under the United Nations Framework Convention on Climate Change are also continuing.

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

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

The EPA's greenhouse gas reporting rule requires annual reporting of CO_2 equivalent emissions in metric tons for a company's operational control of facilities. Based on ownership or financial control of facilities, the Southern Company system's 2012 greenhouse gas emissions were approximately 99 million metric tons of CO_2 equivalent. The preliminary estimate of the Southern Company system's 2013 greenhouse gas emissions on the same basis is approximately 103 million metric tons of CO_2 equivalent. The level of greenhouse gas emissions from year to year will depend on the level of generation and mix of fuel sources and other factors.

PSC Matters

Alabama Power

Retail Rate Adjustments

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

Rate RSE

Alabama Power operates under a rate stabilization and equalization plan (Rate RSE) approved by the Alabama PSC. Alabama Power's Rate RSE adjustments are based on forward-looking information for the applicable upcoming calendar year. Rate adjustments for any two-year period, when averaged together, cannot exceed 4.0% and any annual adjustment is limited to 5.0%. If Alabama Power's actual retail return is above the allowed equity return range, customer refunds will be required; however, there is no provision for additional customer billings should the actual retail return fall below the allowed equity return range. Prior to 2014, retail rates remained unchanged when the retail return on common equity (ROE) was projected to be between 13.0% and 14.5%.

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

- Eliminate the provision of Rate RSE establishing an allowed range of ROE.

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

- Provide eligibility for a performance-based adder of seven basis points, or 0.07%, to the WCE adjusting point if Alabama Power (i) has an "A" credit rating equivalent with at least one of the recognized rating agencies or (ii) is in the top one-third of a designated customer value benchmark survey.

Substantially all other provisions of Rate RSE were unchanged.

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

Rate CNP

Alabama Power's retail rates, approved by the Alabama PSC, provide for adjustments to recognize the placing of new generating facilities into retail service under rate certificated new plant (Rate CNP). Alabama Power may also recover retail costs associated with certificated PPAs under rate certificated new plant (Rate CNP PPA). There was no adjustment to Rate CNP PPA in 2012. On March 5, 2013, the Alabama PSC issued a consent order that Alabama Power leave in effect the current Rate CNP PPA factor for billings for the period April 1, 2013 through March 31, 2014. It is anticipated that no adjustment will be made to Rate CNP PPA in 2014. As of December 31, 2013, Alabama Power had an under recovered certificated PPA balance of $18 million, all of which is included in deferred under recovered regulatory clause revenues in the balance sheet.

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

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

Environmental Accounting Order

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

Compliance and Pension Cost Accounting Order

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

Natural Disaster Reserve

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

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

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

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

Nuclear Outage Accounting Order

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

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

Non-Nuclear Outage Accounting Order

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

Georgia Power

Rate Plans

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

On December 17, 2013, the Georgia PSC voted to approve the Alternate Rate Plan for Georgia Power which became effective January 1, 2014 and continues through December 31, 2016 (2013 ARP). The 2013 ARP reflects the settlement agreement among Georgia Power, the Georgia PSC's Public Interest Advocacy Staff, and 11 of the 13 intervenors, which was filed with the Georgia PSC on November 18, 2013.

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

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

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

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

Under the 2013 ARP, Georgia Power's retail ROE is set at 10.95%, and earnings are evaluated against a retail ROE range of 10.00% to 12.00%. Two-thirds of any earnings above 12.00% will be directly refunded to customers, with the remaining one-third retained by Georgia Power. There will be no recovery of any earnings shortfall below 10.00% on an actual basis. However, if at any time during the term of the 2013 ARP, Georgia Power projects that its retail earnings will be below 10.00% for any calendar year, it may petition the Georgia PSC for implementation of the Interim Cost Recovery (ICR) tariff that would be used to adjust Georgia Power's earnings back to a 10.00% retail ROE. The Georgia PSC would have 90 days to rule on Georgia Power's request. The ICR tariff will expire at the earlier of January 1, 2017 or the end of the calendar year in which the ICR tariff becomes effective. In lieu of requesting implementation of an ICR tariff, or if the Georgia PSC chooses not to implement the ICR tariff, Georgia Power may file a full rate case.

Except as provided above, Georgia Power will not file for a general base rate increase while the 2013 ARP is in effect. Georgia Power is required to file a general rate case by July 1, 2016, in response to which the Georgia PSC would be expected to determine whether the 2013 ARP should be continued, modified, or discontinued.

Integrated Resource Plans

See "Environmental Matters – Environmental Statutes and Regulations – Air Quality," "– Water Quality," and "– Coal Combustion Residuals" and "Rate Plans" herein for additional information regarding proposed and final EPA rules and regulations, including the MATS rule for coal- and oil-fired electric utility steam generating units, revisions to effluent limitations guidelines for steam electric power plants, and additional regulation of coal combustion residuals; the State of Georgia's Multi-Pollutant Rule; Georgia Power's analysis of the potential costs and benefits of installing the required controls on its fossil generating units in light of these regulations; and Georgia Power's latest triennial Integrated Resource Plan as approved by the Georgia PSC (2013 IRP).

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

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

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

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

In the 2013 ARP, the Georgia PSC approved the amortization of the CWIP balances related to environmental projects that will not be completed at Plant Branch Units 1 through 4 and Plant Yates Units 6 and 7 over nine years beginning in January 2014 and the amortization of any remaining net book values of Plant Branch Unit 2 from October 2013 to December 2022, Plant Branch Unit 1 from May 2015 to December 2020, Plant Branch Unit 3 from May 2015 to December 2023, and Plant Branch Unit 4 from May 2015 to December 2024. The Georgia PSC deferred a decision regarding the appropriate recovery period for the costs associated with unusable materials and supplies remaining at the retiring plants to Georgia Power's next base rate case, which Georgia Power expects to file in 2016 (2016 Rate Case). In the 2013 IRP, the Georgia PSC also deferred decisions regarding the recovery of any fuel related costs that could be incurred in connection with the retirement units to be addressed in future fuel cases.

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

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

Renewables Development

On December 17, 2013, four PPAs totaling 50 MWs of utility scale solar generation under the Georgia Power Advanced Solar Initiative (GPASI) were approved by the Georgia PSC, with Georgia Power as the purchaser. These contracts will begin in 2015 and end in 2034. The resulting purchases will be for energy only and recovered through

Georgia Power's fuel cost recovery mechanism. Under the 2013 IRP, the Georgia PSC approved an additional 525 MWs of solar generation to be purchased by Georgia Power. The 525 MWs will be divided into 425 MWs of utility scale projects and 100 MWs of distributed generation.

On November 4, 2013, Georgia Power filed an application for the certification of two PPAs which were executed on April 22, 2013 for the purchase of energy from two wind farms in Oklahoma with capacity totaling 250 MWs that will begin in 2016 and end in 2035.

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

Storm Damage Recovery

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

Retail Fuel Cost Recovery

The traditional operating companies each have established fuel cost recovery rates approved by their respective state PSCs. Fuel cost recovery revenues are adjusted for differences in actual recoverable fuel costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will not have a significant effect on Southern Company's revenues or net income, but will affect any cash flow. The traditional operating companies continuously monitor their under or over recovered fuel cost balances. At December 31, 2013, total over recovered fuel costs in the balance sheets of Alabama Power, Georgia Power, and Mississippi Power were approximately $115 million, and total under recovered fuel costs in the balance sheet of Gulf Power were approximately $21 million. The lower cost of natural gas resulted in total over recovered fuel costs in the balance sheets of Georgia Power, Gulf Power, and Mississippi Power of approximately $303 million at December 31, 2012. Total under recovered fuel costs were approximately $4 million in the balance sheet of Alabama Power at December 31, 2012.

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

Income Tax Matters

Bonus Depreciation

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

Construction Program

The subsidiary companies of Southern Company are engaged in continuous construction programs to accommodate existing and estimated future loads on their respective systems. The Southern Company system intends to continue its strategy of developing and constructing new generating facilities, as well as adding or changing fuel sources for certain existing units, adding environmental control equipment, and expanding the transmission and distribution systems. For the traditional operating companies, major generation construction projects are subject to state PSC approvals in order to be included in retail rates. While Southern Power generally constructs and acquires generation assets covered by long-term PPAs, any uncontracted capacity could negatively affect future earnings. The construction programs of the traditional operating companies and Southern Power are currently estimated to include an investment of approximately $6.1 billion, $5.4 billion, and $4.5 billion for 2014, 2015, and 2016, respectively.

The two largest construction projects currently underway in the Southern Company system are Plant Vogtle Units 3 and 4 (45.7% ownership interest by Georgia Power in two units, each with approximately 1,100 MWs) and the 582-MW Kemper IGCC (in which Mississippi Power is ultimately expected to hold an 85% ownership interest). See Note 3 to the financial statements under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" and "Integrated Coal Gasification Combined Cycle" for additional information.

In 2013, the Company incurred pre-tax charges of $1.2 billion ($729 million after-tax) for revisions of estimated costs expected to be incurred on Mississippi Power's construction of the Kemper IGCC above the $2.88 billion cost cap established by the Mississippi PSC, net of the DOE Grants and excluding the Cost Cap Exceptions. In subsequent periods, any further changes in the estimated costs to complete construction of the Kemper IGCC subject to the $2.88 billion cost cap will be reflected in the Company's statements of income and these changes could be material. Additionally, there are certain risks associated with the construction program in general and certain risks associated with the licensing, construction, and operation of nuclear generating units in particular, including potential impacts that could result from a major incident at a nuclear facility anywhere in the world. The ultimate outcome of these events cannot be determined at this time.

Other Matters

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

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

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

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

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

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

On November 19, 2013, the U.S. District Court for the District of Columbia ordered the DOE to cease collecting spent fuel depositary fees from nuclear power plant operators until such time as the DOE either complies with the Nuclear Waste Policy Act of 1982 or until the U.S. Congress enacts an alternative waste management plan. In accordance with the court's order, the DOE has submitted a proposal to the U.S. Congress to change the fee to zero. That proposal is pending before the U.S. Congress and will become effective after 90 days of legislative session from the time of submittal unless the U.S. Congress enacts legislation that impacts the proposed fee change. The DOE's petition for rehearing of the November 2013 decision is currently pending and Alabama Power and Georgia Power are continuing to pay the fee of approximately $13 million and $15 million annually, respectively, based on their ownership interest.

The ultimate outcome of this matter cannot be determined at this time.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

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

Electric Utility Regulation

Southern Company's traditional operating companies, which comprised approximately 94% of Southern Company's total operating revenues for 2013, are subject to retail regulation by their respective state PSCs and wholesale regulation by the FERC. These regulatory agencies set the rates the traditional operating companies are permitted to charge customers based on allowable costs. As a result, the traditional operating companies apply accounting standards which require the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of the accounting standards has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the traditional operating companies; therefore, the accounting estimates inherent in specific costs such as depreciation, asset retirement obligations, and pension and postretirement benefits have less of a direct impact on the Company's results of operations and financial condition than they would on a non-regulated company.

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

Contingent Obligations

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

Pension and Other Postretirement Benefits

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

Key elements in determining Southern Company's pension and other postretirement benefit expense in accordance with GAAP are the expected long-term return on plan assets and the discount rate used to measure the benefit plan obligations and the periodic benefit plan expense for future periods. The expected long-term return on postretirement benefit plan assets is based on Southern Company's investment strategy, historical experience, and expectations for long-term rates of return that consider external actuarial advice. Southern Company determines the long-term return on plan assets by applying the long-term rate of expected returns on various asset classes to Southern Company's target asset allocation. Southern Company discounts the future cash flows related to its postretirement benefit plans using a single-point discount rate for each plan developed from the weighted average of market-observed yields for high quality fixed income securities with maturities that correspond to expected benefit payments.

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

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

N/A – Not applicable

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

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

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

FINANCIAL CONDITION AND LIQUIDITY

Overview

Although earnings in 2013 were negatively affected by revisions to the cost estimate for the Kemper IGCC, Southern Company's financial condition remained stable at December 31, 2013. These charges for the year ended December 31, 2013 have resulted in cash expenditures of \$375.1 million with no recovery as of December 31, 2013 and are expected to result in future cash expenditures (primarily in 2014) of approximately \$805 million with no recovery. Southern Company's cash requirements primarily consist of funding ongoing operations, common stock dividends, capital expenditures, and debt maturities. The Southern Company system's capital expenditures and other investing activities include investments to meet projected long-term demand requirements, to comply with environmental regulations, and for restoration following major storms. Operating cash flows provide a substantial portion of the Southern Company system's cash needs. For the three-year period from 2014 through 2016, Southern Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. The Southern Company system's projected capital expenditures in that period include investments to build new generation facilities, to maintain existing generation facilities, to add environmental equipment for existing generating units, and to expand and improve transmission and distribution facilities. Southern Company plans to finance future cash needs in excess of its operating cash flows primarily through debt and equity issuances. Southern Company intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements to meet future capital and liquidity needs. See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

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

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

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

Net cash used for financing activities totaled $324 million in 2013 due to redemptions of long-term debt and payments of common stock dividends, partially offset by issuances of long-term debt and common stock and an increase in notes payable. Net cash used for financing activities totaled $417 million in 2012 due to redemptions of long-term debt, the repurchase of common stock, and payments of common stock dividends, partially offset by issuances of long-term debt. Fluctuations in cash flow from financing activities vary from year to year based on capital needs and the maturity or redemption of securities.

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

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

Sources of Capital

Southern Company intends to meet its future capital needs through internal cash flow and external security issuances. Equity capital can be provided from any combination of the Company's stock plans, private placements, or public offerings. The amount and timing of additional equity capital to be raised in 2014, as well as in subsequent years, will be contingent on Southern Company's investment opportunities and capital requirements.

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

On February 20, 2014, Georgia Power and the DOE entered into a loan guarantee agreement (Loan Guarantee Agreement), pursuant to which the DOE agreed to guarantee borrowings to be made by Georgia Power under a multi-advance credit facility (FFB Credit Facility) among Georgia Power, the DOE, and the Federal Financing Bank (FFB). Georgia Power's reimbursement obligations to the DOE are secured by a first priority lien on (i) Georgia Power's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4 and (ii) Georgia Power's rights and obligations under the principal contracts relating to Plant Vogtle Units 3 and 4. Under the FFB Credit Facility, Georgia Power may make term loan borrowings through the FFB. Proceeds of borrowings made under the FFB Credit Facility will be used to reimburse Georgia Power for a portion of certain costs of construction relating to Plant Vogtle Units 3 and 4 that are eligible for financing under the Loan Guarantee Agreement (Eligible Project Costs). Aggregate borrowings under the FFB Credit Facility may not exceed the lesser of (i) 70% of Eligible Project Costs or (ii) approximately $3.46 billion. See Note 6 to the financial statements for additional information.

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

Kemper IGCC. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for information regarding legislation related to the securitization of certain costs of the Kemper IGCC.

The issuance of securities by the traditional operating companies is generally subject to the approval of the applicable state PSC. The issuance of all securities by Mississippi Power and Southern Power and short-term securities by Georgia Power is generally subject to regulatory approval by the FERC. Additionally, with respect to the public offering of securities, Southern Company and certain of its subsidiaries file registration statements with the SEC under the Securities Act of 1933, as amended (1933 Act). The

amounts of securities authorized by the appropriate regulatory authorities, as well as the securities registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.
Southern Company, each traditional operating company, and Southern Power obtain financing separately without credit support from any affiliate. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of each company are not commingled with funds of any other company in the Southern Company system.
Southern Company's current liabilities frequently exceed current assets because of the continued use of short-term debt as a funding source to meet scheduled maturities of long-term debt, as well as cash needs, which can fluctuate significantly due to the seasonality of the business of the Southern Company system. To meet short-term cash needs and contingencies, Southern Company has substantial cash flow from operating activities and access to capital markets, including commercial paper programs which are backed by bank credit facilities.
At December 31, 2013, Southern Company and its subsidiaries had approximately $659 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2013 were as follows:

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

(a) No credit arrangements expire in 2017.
See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.
A portion of the unused credit with banks is allocated to provide liquidity support to the traditional operating companies' variable rate pollution control revenue bonds and commercial paper programs. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2013 was approximately $1.8 billion. In addition, at December 31, 2013, the traditional operating companies had $442 million of fixed rate pollution control revenue bonds that will be required to be remarketed within the next 12 months.
Southern Company and its subsidiaries expect to renew their credit arrangements as needed, prior to expiration. Most of these arrangements contain covenants that limit debt levels and contain cross default provisions to other indebtedness (including guarantee obligations) that are restricted only to the indebtedness of the individual company. Such cross default provisions to other indebtedness would trigger an event of default if the applicable borrower defaulted on indebtedness or guarantee obligations over a specified threshold. Southern Company, the traditional operating companies, and Southern Power are currently in compliance with all such covenants. None of the arrangements contain material adverse change clauses at the time of borrowings.
Southern Company, the traditional operating companies, and Southern Power make short-term borrowings primarily through commercial paper programs that have the liquidity support of committed bank credit arrangements. Southern Company, the traditional operating companies, and Southern Power may also borrow through various other arrangements with banks. Commercial paper and short-term bank loans are included in notes payable in the balance

sheets.

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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 (in millions)	Weighted Average Interest Rate	Average Outstanding (in millions)	Weighted Average Interest Rate	Maximum Amount Outstanding (in millions)
December 31, 2013:					
Commercial paper	$1,082	0.2 %	$993	0.3 %	$1,616
Short-term bank debt	400	0.9 %	107	0.9 %	400
Total	$1,482	0.4 %	$1,100	0.3 %	
December 31, 2012:					
Commercial paper	$820	0.3 %	$550	0.3 %	$938
Short-term bank debt	—	— %	116	1.2 %	300
Total	$820	0.3 %	$666	0.5 %	
December 31, 2011:					
Commercial paper	$654	0.3 %	$697	0.3 %	$1,586
Short-term bank debt	200	1.2 %	14	1.2 %	200
Total	$854	0.5 %	$711	0.3 %	

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

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

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

Financing Activities

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

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

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

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

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

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

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

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

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

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

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

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

The bank loans and the MBFC taxable revenue bonds have covenants that limit debt levels to 65% of total capitalization, as defined in the agreements. For purposes of these definitions, debt excludes the long-term debt payable to affiliated trusts and other hybrid securities and, for Mississippi Power, securitized debt relating to the securitization of certain costs of the Kemper IGCC. At December 31, 2013, Georgia Power and Mississippi Power were in compliance with their respective debt limits.

In addition, these bank loans and the MBFC taxable revenue bonds contain cross default provisions that would be triggered if the borrower defaulted on other indebtedness (including guarantee obligations) above a specified threshold. The cross default provisions are restricted to the indebtedness, including any guarantee obligations, of the company that has such bank loans. Georgia Power and Mississippi Power are currently in compliance with all such covenants.

Gulf Power purchased and held $42 million aggregate principal amount of Development Authority of Monroe County (Georgia) Pollution Control Revenue Bonds (Gulf Power Company Plant Scherer Project), First Series 2002 (First Series 2002 Bonds) and

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

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

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

In September 2013, Mississippi Power entered into a nitrogen supply agreement for the air separation unit of the Kemper IGCC, which resulted in a capital lease obligation at inception of $83 million with an annual interest rate of 4.9%.

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

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

Subsequent to December 31, 2013, Georgia Power made initial borrowings under the FFB Credit Facility in an aggregate principal amount of $1.0 billion. The interest rate applicable to $500 million of the initial advance under the FFB Credit Facility is 3.860% for an interest period that extends to February 20, 2044 (the final maturity date) and the interest rate applicable to the remaining $500 million is 3.488% for an interest period that extends to February 20, 2029 and will be reset from time to time thereafter through the final maturity date. The final maturity date for all advances under the FFB Credit Facility is February 20, 2044. The proceeds of the initial borrowings under the FFB Credit Facility were used to reimburse Georgia Power for Eligible Project Costs relating to the construction of Plant Vogtle Units 3 and 4. Georgia Power's reimbursement obligations to the DOE are secured by a first priority lien on (i) Georgia Power's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4 and (ii) Georgia Power's rights and obligations under the principal contracts relating to Plant Vogtle Units 3 and 4. See Note 6 to the financial statements for additional information.

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

In addition to any financings that may be necessary to meet capital requirements and contractual obligations, Southern Company and its subsidiaries plan to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

Credit Rating Risk

Southern Company and its subsidiaries do not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change of certain subsidiaries to BBB and Baa2, or BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel purchases, fuel transportation and storage, emissions allowances, energy price risk management, and construction of new generation.

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

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

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

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

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

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

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

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

Market Price Risk

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

To mitigate future exposure to a change in interest rates, Southern Company and certain of its subsidiaries enter into derivatives that have been designated as hedges. Derivatives outstanding at December 31, 2013 have a notional amount of $350 million and are related to fixed and floating rate obligations which expire in 2014. The weighted average interest rate on $3.3 billion of long-term and short-term variable interest rate exposure that has not been hedged at January 1, 2014 was 0.70%. If Southern Company sustained a 100 basis point change in interest rates for all unhedged variable rate long-term debt and short-term bank loans, the change would affect annualized interest expense by approximately $33 million at January 1, 2014. See Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements for additional information.

Due to cost-based rate regulation and other various cost recovery mechanisms, the traditional operating companies continue to have limited exposure to market volatility in interest rates, foreign currency, commodity fuel prices, and prices of electricity. In addition, Southern Power's exposure to market volatility in commodity fuel prices and prices of electricity is limited because its long-term sales contracts shift substantially all fuel cost responsibility to the purchaser. However, Southern Power has been and may continue to be exposed to market volatility in energy-related commodity prices as a result of uncontracted generating capacity. To mitigate residual risks relative to movements in electricity prices, the traditional operating companies enter into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, financial hedge contracts for natural gas purchases. The traditional operating companies continue to manage fuel-hedging programs implemented per the guidelines of their respective state PSCs. Southern Company had no material change in market risk exposure for the year ended December 31, 2013 when compared to the December 31, 2012 reporting period.

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

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

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

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

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

* million British thermal units (mmBtu)

The weighted average swap contract cost above market prices was approximately $0.10 per mmBtu as of December 31, 2013 and $0.39 per mmBtu as of December 31, 2012. The change in option fair value is primarily attributable to the volatility of the market and the underlying change in the natural gas price. The majority of the natural gas hedge gains and losses are recovered through the traditional operating companies' fuel cost recovery clauses.

At December 31, 2013 and 2012, substantially all of the Southern Company system's energy-related derivative contracts were designated as regulatory hedges and are related to the applicable company's fuel-hedging program. Therefore, gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the energy cost recovery clause. Certain other gains and losses on energy-related derivatives, designated as cash flow hedges, are initially deferred in other comprehensive income before being recognized in income in the same period as the hedged transaction. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred and were not material for any year presented.

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Southern Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. See Note 10 to the financial statements for further discussion of fair value measurements. The maturities of the energy-related derivative contracts, which are all Level 2 of the fair value hierarchy, at December 31, 2013 were as follows:

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

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

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

Capital Requirements and Contractual Obligations

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

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

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

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

Note 3 to the financial statements under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" and "Integrated Coal Gasification Combined Cycle" for additional information.

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

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

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.

(a) Variable rate interest obligations are estimated based on rates as of January 1, 2014, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk. Long-term debt excludes capital lease amounts (shown separately).

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

(c) For additional information, see Notes 1 and 11 to the financial statements.

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

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

(f) The Southern Company system provides estimated capital expenditures for a three-year period, including capital expenditures and compliance costs associated with environmental regulations. Estimates reflect the proposed sale of 15% of the Kemper IGCC to SMEPA. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information. These amounts exclude contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements which are reflected separately. At December 31, 2013, significant purchase commitments were outstanding in connection with the construction program. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" herein for additional information.

(g) Primarily includes commitments to purchase coal, nuclear fuel, and natural gas, as well as the related transportation and storage. In most cases, these contracts contain provisions for price escalation, minimum purchase levels, and other financial commitments. Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected for natural gas purchase commitments have been estimated based on the New York Mercantile Exchange future prices at December 31, 2013.

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

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

(j) Projections of nuclear decommissioning trust fund contributions are based on the 2010 ARP for 2014 and on the 2013 ARP thereafter for Georgia Power. See Note 1 to the financial statements under "Nuclear Decommissioning" for additional information.

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

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Cautionary Statement Regarding Forward-Looking Statements

Southern Company's 2013 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail sales, retail rates, the strategic goals for the wholesale business, customer growth, economic recovery, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related estimated expenditures, access to sources of capital, projections for the qualified pension plan, postretirement benefit plan, and nuclear decommissioning trust fund contributions, financing activities, completion dates of construction projects, plans and estimated costs for new generation resources, filings with state and federal regulatory authorities, impact of the ATRA, estimated sales and purchases under new power sale and purchase agreements, and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, environmental laws including regulation of water, coal combustion residuals, and emissions of sulfur, nitrogen, carbon, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, and also changes in tax and other laws and regulations to which Southern Company and its subsidiaries are subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including the pending EPA civil actions against certain Southern Company subsidiaries, FERC matters, and Internal Revenue Service and state tax audits;
- the effects, extent, and timing of the entry of additional competition in the markets in which Southern Company's subsidiaries operate;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the recent recession, population and business growth (and declines), the effects of energy conservation measures, including from the development and deployment of alternative energy sources such as self-generation and distributed generation technologies, and any potential economic impacts resulting from federal fiscal decisions;
- available sources and costs of fuels;
- effects of inflation;
- ability to control costs and avoid cost overruns during the development and construction of facilities, which include the development and construction of facilities with designs that have not been finalized or previously constructed, including changes in labor costs and productivity factors, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay or non-performance under construction or other agreements, delays associated with start-up activities, including major equipment failure, system integration, and operations, and/or unforeseen engineering problems;
- ability to construct facilities in accordance with the requirements of permits and licenses and to satisfy any operational and environmental performance standards, including the requirements of tax credits and other incentives;
- investment performance of Southern Company's employee and retiree benefit plans and the Southern Company system's nuclear decommissioning trust funds;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms;
- regulatory approvals and actions related to Plant Vogtle Units 3 and 4, including Georgia PSC approvals and NRC actions;
- actions related to cost recovery for the Kemper IGCC, including actions relating to proposed securitization, Mississippi PSC approval of Mississippi Power's proposed rate recovery plan, as ultimately amended, which includes

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

- Mississippi PSC review of the prudence of Kemper IGCC costs;
- the outcome of any legal or regulatory proceedings regarding the Mississippi PSC's issuance of the CPCN for the Kemper IGCC, the settlement agreement between Mississippi Power and the Mississippi PSC, or the State of Mississippi

legislation designed to enhance the Mississippi PSC's authority to facilitate development and construction of baseload generation in the State of Mississippi;

- the inherent risks involved in operating and constructing nuclear generating facilities, including environmental, health, regulatory, natural disaster, terrorism, or financial risks;
- the performance of projects undertaken by the non-utility businesses and the success of efforts to invest in and develop new opportunities;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to Southern Company or its subsidiaries;
- the ability of counterparties of Southern Company and its subsidiaries to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Southern Company system's business resulting from terrorist incidents and the threat of terrorist incidents, including cyber intrusion;
- interest rate fluctuations and financial market conditions and the results of financing efforts, including Southern Company's and its subsidiaries' credit ratings;
- the impacts of any potential U.S. credit rating downgrade or other sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on currency exchange rates, counterparty performance, and the economy in general, as well as potential impacts on the benefits of the DOE loan guarantees;
- the ability of Southern Company and its subsidiaries to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Southern Company system's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by Southern Company from time to time with the SEC.

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

CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2013, 2012, and 2011
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	2013	2012	2011
		(in millions)	
Operating Revenues:			
Retail revenues	$14,541	$14,187	$15,071
Wholesale revenues	1,855	1,675	1,905
Other electric revenues	639	616	611
Other revenues	52	59	70
Total operating revenues	17,087	16,537	17,657
Operating Expenses:			
Fuel	5,510	5,057	6,262
Purchased power	461	544	608
Other operations and maintenance	3,846	3,772	3,938
Depreciation and amortization	1,901	1,787	1,717
Taxes other than income taxes	934	914	901
Estimated loss on Kemper IGCC	1,180	—	—
Total operating expenses	13,832	12,074	13,426
Operating Income	3,255	4,463	4,231
Other Income and (Expense):			
Allowance for equity funds used during construction	190	143	153
Interest income	19	40	21
Interest expense, net of amounts capitalized	(824)	(859)	(857)
Other income (expense), net	(81)	(38)	(61)
Total other income and (expense)	(696)	(714)	(744)
Earnings Before Income Taxes	2,559	3,749	3,487
Income taxes	849	1,334	1,219
Consolidated Net Income	1,710	2,415	2,268
Dividends on Preferred and Preference Stock of Subsidiaries	66	65	65
Consolidated Net Income After Dividends on Preferred and Preference Stock of Subsidiaries	$1,644	$2,350	$2,203
Common Stock Data:			
Earnings per share (EPS)—			
Basic EPS	$1.88	$2.70	$2.57
Diluted EPS	1.87	2.67	2.55
Average number of shares of common stock outstanding — (in millions)			
Basic	877	871	857
Diluted	881	879	864

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

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

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

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

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

	2013	2012	2011
		(in millions)	
Operating Activities:			
Consolidated net income	$1,710	$2,415	$2,268
Adjustments to reconcile consolidated net income to net cash provided from operating activities —			
Depreciation and amortization, total	2,298	2,145	2,048
Deferred income taxes	496	1,096	1,155
Investment tax credits	302	128	85
Allowance for equity funds used during construction	(190)	(143)	(153)
Pension, postretirement, and other employee benefits	131	(398)	(45)
Stock based compensation expense	59	55	42
Estimated loss on Kemper IGCC	1,180	—	—
Retail fuel cost over recovery - long-term	(123)	123	—
Other, net	82	(72)	(70)
Changes in certain current assets and liabilities —			
-Receivables	(153)	234	362
-Fossil fuel stock	481	(452)	(62)
-Materials and supplies	36	(97)	(60)
-Other current assets	(11)	(37)	(17)
-Accounts payable	72	(89)	(5)
-Accrued taxes	(85)	(71)	330
-Accrued compensation	(138)	(28)	10
-Retail fuel cost over recovery - short-term	(66)	129	(3)
-Other current liabilities	16	(40)	18
Net cash provided from operating activities	6,097	4,898	5,903
Investing Activities:			
Property additions	(5,463)	(4,809)	(4,525)
Investment in restricted cash	(149)	(280)	1
Distribution of restricted cash	96	284	63
Nuclear decommissioning trust fund purchases	(986)	(1,046)	(2,195)
Nuclear decommissioning trust fund sales	984	1,043	2,190
Cost of removal, net of salvage	(131)	(149)	(93)
Change in construction payables, net	(126)	(84)	198
Other investing activities	33	(127)	178
Net cash used for investing activities	(5,742)	(5,168)	(4,183)
Financing Activities:			
Increase (decrease) in notes payable, net	662	(30)	(438)
Proceeds —			
Long-term debt issuances	2,938	4,404	3,719
Interest-bearing refundable deposit related to asset sale	—	150	—
Preference stock	50	—	—
Common stock issuances	695	397	723
Redemptions and repurchases —			
Long-term debt	(2,830)	(3,169)	(3,170)
Common stock repurchased	(20)	(430)	—
Payment of common stock dividends	(1,762)	(1,693)	(1,601)

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

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

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

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

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

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

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

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

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

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

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

	2013	2012	2013	2012
	(in millions)		(percent of total)	
Redeemable Preferred Stock of Subsidiaries:				
Cumulative preferred stock				
$100 par or stated value — 4.20% to 5.44%				
Authorized — 20 million shares				
Outstanding — 1 million shares	81	81		
$1 par value — 5.20% to 5.83%				
Authorized — 28 million shares				
Outstanding — 12 million shares: $25 stated value	294	294		
Total redeemable preferred stock of subsidiaries (annual dividend requirement — $20 million)	375	375	0.9	1.0
Common Stockholders' Equity:				
Common stock, par value $5 per share —	4,461	4,389		
Authorized — 1.5 billion shares				
Issued — 2013: 893 million shares				
— 2012: 878 million shares				
Treasury — 2013: 5.7 million shares				
— 2012: 10.0 million shares				
Paid-in capital	5,362	4,855		
Treasury, at cost	(250)	(450)		
Retained earnings	9,510	9,626		
Accumulated other comprehensive income (loss)	(75)	(123)		
Total common stockholders' equity	19,008	18,297	45.8	47.3
Preferred and Preference Stock of Subsidiaries:				
Non-cumulative preferred stock				
$25 par value — 6.00% to 6.13%				
Authorized — 60 million shares				
Outstanding — 2 million shares	45	45		
Preference stock				
Authorized — 65 million shares				
Outstanding—$1 par value	343	343		
— 5.63% to 6.50% — 14 million shares (non-cumulative)				
Outstanding — $100 par or stated value	368	319		
— 5.60% to 6.50% — 2013: 4 million shares (non-cumulative)				
— 2012: 3 million shares (non-cumulative)				
Total preferred and preference stock of subsidiaries (annual dividend requirement — $48 million)	756	707	1.8	1.8
Total stockholders' equity	19,764	19,004		
Total Capitalization	$41,483	$38,653	100.0 %	100.0 %

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

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
For the Years Ended December 31, 2013, 2012, and 2011
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	Number of Common Shares		Common Stock						
	Issued	Treasury	Par Value	Paid-In Capital	Treasury	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Preferred and Preference Stock of Subsidiaries	Total
	(in thousands)		(in millions)						
Balance at December 31, 2010	843,814	(474)	$4,219	$3,702	$(15)	$8,366	$(70)	$707	$16,909
Net income after dividends on preferred and preference stock of subsidiaries	—	—	—	—	—	2,203	—	—	2,203
Other comprehensive income (loss)	—	—	—	—	—	—	(41)	—	(41)
Stock issued	21,850	—	109	616	—	—	—	—	725
Stock-based compensation	—	—	—	89	—	—	—	—	89
Cash dividends	—	—	—	—	—	(1,601)	—	—	(1,601)
Other	—	(65)	—	3	(2)	—	—	—	1
Balance at December 31, 2011	865,664	(539)	4,328	4,410	(17)	8,968	(111)	707	18,285
Net income after dividends on preferred and preference stock of subsidiaries	—	—	—	—	—	2,350	—	—	2,350
Other comprehensive income (loss)	—	—	—	—	—	—	(12)	—	(12)
Stock issued	12,139	—	61	336	—	—	—	—	397
Stock repurchased, at cost	—	(9,440)	—	—	(430)	—	—	—	(430)
Stock-based compensation	—	—	—	106	—	—	—	—	106
Cash dividends	—	—	—	—	—	(1,693)	—	—	(1,693)
Other	—	(56)	—	3	(3)	1	—	—	1
Balance at December 31, 2012	877,803	(10,035)	4,389	4,855	(450)	9,626	(123)	707	19,004
Net income after dividends on preferred and preference stock of subsidiaries	—	—	—	—	—	1,644	—	—	1,644
Other comprehensive income (loss)	—	—	—	—	—	—	48	—	48
Stock issued	14,930	4,443	72	441	203	—	—	49	765

Stock-based compensation	—	—	—	65	—	—	—	—	65
Cash dividends	—	—	—	—	—	(1,762)	—	—	(1,762)
Other	—	(55)	—	1	(3)	2	—	—	—
Balance at December 31, 2013	892,733	(5,647)	$4,461	$5,362	$(250)	$9,510	$ (75)	$756	$19,764

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

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

Index to the Notes to Financial Statements

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 2013 Annual Report

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(o) Recorded over the life of the underlying hedged purchase contracts, which generally do not exceed five years. Upon final settlement, actual costs incurred are recovered through the energy cost recovery clause.

In the event that a portion of a traditional operating company's operations is no longer subject to applicable accounting rules for rate regulation, such company would be required to write off to income or reclassify to accumulated other comprehensive income

(OCI) related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the traditional operating company would be required to determine if any impairment to other assets, including plant, exists and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are to be reflected in rates. See Note 3 under "Retail Regulatory Matters – Alabama Power," "Retail Regulatory Matters – Georgia Power," and "Integrated Coal Gasification Combined Cycle" for additional information.

Revenues

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

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

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense generally includes fuel transportation costs and the cost of purchased emissions allowances as they are used. Fuel expense also includes the amortization of the cost of nuclear fuel and a charge, based on nuclear generation, for the permanent disposal of spent nuclear fuel. See Note 3 under "Nuclear Fuel Disposal Costs" for additional information.

Income and Other Taxes

Southern Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income.

In accordance with regulatory requirements, deferred federal investment tax credits (ITCs) for the traditional operating companies are amortized over the lives of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $16 million in 2013, $23 million in 2012, and $19 million in 2011. At December 31, 2013, all ITCs available to reduce federal income taxes payable had not been utilized. The remaining ITCs will be carried forward and utilized in future years. Additionally, several subsidiaries have state ITCs, which are recognized in the period in which the credit is claimed on the state income tax return. A portion of the state ITCs available to reduce state income taxes payable was not utilized currently and will be carried forward and utilized in future years.

Under the American Recovery and Reinvestment Act of 2009, certain projects at Southern Power are eligible for ITCs or cash grants. Southern Power has elected to receive ITCs. The credits are recorded as a deferred credit, and are amortized to income tax expense over the life of the asset. Credits amortized in this manner amounted to $5.5 million and $2.6 million in 2013 and 2012, respectively. Furthermore, the tax basis of the asset is reduced by 50% of the credits received, resulting in a net deferred tax asset. Southern Power has elected to recognize the tax benefit of this basis difference as a reduction to income tax expense as costs are incurred during the construction period.

In accordance with accounting standards related to the uncertainty in income taxes, Southern Company recognizes tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 5 under "Unrecognized Tax Benefits" for additional information.

Property, Plant, and Equipment

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

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

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

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

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to other operations and maintenance expenses as incurred or performed with the exception of nuclear refueling costs, which are recorded in accordance with specific state PSC orders. Alabama Power and Georgia Power defer and amortize nuclear refueling costs over the unit's operating cycle. The refueling cycles for Alabama Power and Georgia Power range from 18 to 24 months for each unit. In accordance with a Georgia PSC order, Georgia Power deferred the costs of certain significant inspection costs for the combustion turbine units at Plant McIntosh and amortized such costs over 10 years, which approximated the expected maintenance cycle of the units. All inspection costs were fully amortized in 2013.

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

	Asset Balances at December 31,	
	2013	2012
	(in millions)	
Office building	$61	$61
Nitrogen plant	83	—
Computer-related equipment	62	58
Gas pipeline	6	—
Less: Accumulated amortization	(48)	(39)
Balance, net of amortization	$164	$80

The amount of non-cash property additions recognized for the years ended December 31, 2013, 2012, and 2011 was $411 million, $524 million, and $929 million, respectively. These amounts are comprised of construction-related accounts payable outstanding at each year end. Also, the amount of non-cash property additions associated with capitalized leases for the years ended December 31, 2013, 2012, and 2011 were $107 million, $14 million, and $21 million, respectively.

Acquisitions

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

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

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

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

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.3% in 2013, 3.2% in 2012, and 3.2% in 2011. Depreciation studies are conducted periodically to update the composite rates. These studies are filed with the respective state PSC and the FERC for the traditional operating companies. Accumulated depreciation for utility plant in service totaled $22.5 billion and $21.5 billion at December 31, 2013 and 2012, respectively. When property subject to composite depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation are removed from the balance sheet accounts, and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired.

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

Depreciation of the original cost of other plant in service is provided primarily on a straight-line basis over estimated useful lives ranging from three to 25 years. Accumulated depreciation for other plant in service totaled $513 million and $479 million at December 31, 2013 and 2012, respectively.

Asset Retirement Obligations and Other Costs of Removal

Asset retirement obligations (ARO) are computed as the present value of the ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. Each traditional operating company has received accounting guidance from the various state PSCs allowing the continued accrual of other future retirement costs for long-lived assets that it does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations are reflected in the balance sheets as a regulatory liability.

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

Details of the asset retirement obligations included in the balance sheets are as follows:

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

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

Nuclear Decommissioning

The U.S. Nuclear Regulatory Commission (NRC) requires licensees of commercial nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. Alabama Power and Georgia Power have external trust funds (Funds) to comply with the NRC's regulations. Use of the Funds is restricted to nuclear decommissioning activities. The Funds are managed and invested in accordance with applicable requirements of various regulatory bodies, including the NRC, the FERC, and state PSCs, as well as the Internal Revenue Service (IRS). The Funds are required to be held by one or more trustees with an individual net worth of at least $100 million. The FERC requires the Funds' managers to exercise the standard of care in investing that a "prudent investor" would use in the same circumstances. The FERC regulations also require that the Funds' managers may not invest in any securities of the utility for which it manages funds or its affiliates, except for investments tied to market indices or other mutual funds. While Southern Company is allowed to prescribe an overall investment policy to the Funds' managers, neither Southern Company nor its subsidiaries or affiliates are allowed to engage in the day-to-day management of the Funds or to mandate individual investment decisions. Day-to-day management of the investments in the Funds is delegated to unrelated third party managers with oversight by the management of Southern Company, Alabama Power, and Georgia Power. The Funds' managers are authorized, within certain investment guidelines, to actively buy and sell securities at their own discretion in order to maximize the return on the Funds' investments. The Funds are invested in a tax-efficient manner in a diversified mix of equity and fixed income securities and are reported as trading securities.

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

The Funds at Georgia Power participate in a securities lending program through the managers of the Funds. Under this program, the Funds' investment securities are loaned to institutional investors for a fee. Securities so loaned are fully collateralized by cash, letters of credit, and securities issued or guaranteed by the U.S. government, its agencies, and the instrumentalities. As of December 31, 2013 and 2012, approximately $32 million and $91 million, respectively, of the fair market value of the Funds' securities were on loan and pledged to creditors under the Funds' managers' securities lending program. The fair value of the collateral received was approximately $33 million and $93 million at December 31, 2013 and 2012, respectively, and can only be sold by the borrower upon the return of the loaned securities. The collateral received is treated as a non-cash item in the statements of cash flows.

At December 31, 2013, investment securities in the Funds totaled $1.5 billion, consisting of equity securities of $896 million, debt securities of $528 million, and $40 million of other securities. At December 31, 2012, investment securities in the Funds totaled $1.3 billion, consisting of equity securities of $718 million, debt securities of $564 million, and $20 million of other securities. These amounts include the investment securities pledged to creditors and collateral received and exclude receivables related to investment income and pending investment sales and payables related to pending investment purchases and the lending pool.

Sales of the securities held in the Funds resulted in cash proceeds of $1.0 billion, $1.0 billion, and $2.2 billion in 2013, 2012, and 2011, respectively, all of which were reinvested. For 2013, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $181 million, of which $5 million related to realized gains and $119 million related to unrealized gains related to securities held in the Funds at December 31, 2013. For 2012, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $137 million, of which $4 million related to realized gains and $75 million related to unrealized gains related to securities held in the Funds at December 31, 2012. For 2011, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $29 million, of which $41 million related to realized gains and $60 million related to unrealized losses related to securities held in the Funds at December 31, 2011. While the investment securities held in the Funds are reported as trading securities, the Funds continue to be managed with a long-term focus. Accordingly, all purchases and sales within the Funds are presented separately in the statements of cash flows as investing cash flows, consistent with the nature of and purpose for which the securities were acquired.

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

At December 31, 2013 and 2012, the accumulated provisions for decommissioning were as follows:

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

Site study cost is the estimate to decommission a specific facility as of the site study year. The decommissioning cost estimates are based on prompt dismantlement and removal of the plant from service. The actual decommissioning costs may vary from these estimates because of changes in the assumed date of decommissioning, changes in NRC requirements, or changes in the assumptions used in making these estimates. The estimated costs of decommissioning as of December 31, 2013 based on the most current studies, which were performed in 2013 for Alabama Power's Plant Farley and in 2012 for the Georgia Power plants, were as follows for Alabama Power's Plant Farley and Georgia Power's ownership interests in Plant Hatch and Plant Vogtle Units 1 and 2:

	Plant Farley	Plant Hatch	Plant Vogtle Units 1 and 2
Decommissioning periods:			
Beginning year	2037	2034	2047
Completion year	2076	2068	2072
	(in millions)		
Site study costs:			
Radiated structures	$1,362	$680	$568
Non-radiated structures	80	51	76
Total site study costs	$1,442	$731	$644

For ratemaking purposes, Alabama Power's decommissioning costs are based on the site study, and Georgia Power's decommissioning costs are based on the NRC generic estimate to decommission the radioactive portion of the facilities and the site study estimate for spent fuel management as of 2012. The Georgia PSC approved annual decommissioning cost for ratemaking of $2 million for Plant Hatch for 2011 through 2013. Under the 2013 ARP, the annual decommissioning cost through 2016 for ratemaking is $4 million and $2 million for Plant Hatch and Plant Vogtle Units 1 and 2, respectively. Georgia Power expects the Georgia PSC to periodically review and adjust, if necessary, the amounts collected in rates for nuclear decommissioning costs. Significant assumptions used to determine these costs for ratemaking were an inflation rate of 4.5% and 2.4% for Alabama Power and Georgia Power, respectively, and a trust earnings rate of 7.0% and 4.4% for Alabama Power and Georgia Power, respectively.

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

Allowance for Funds Used During Construction and Interest Capitalized

In accordance with regulatory treatment, the traditional operating companies record allowance for funds used during construction (AFUDC), which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently from such allowance, AFUDC increases the revenue requirement and is recovered over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in calculating taxable income. Interest related to the construction of new facilities not included in the traditional operating companies' regulated rates is capitalized in accordance with standard interest capitalization requirements. AFUDC and interest capitalized, net of income taxes were 15.0%, 8.2%, and 9.1% of net income for 2013, 2012, and 2011, respectively.

Cash payments for interest totaled $759 million, $803 million, and $832 million in 2013, 2012, and 2011, respectively, net of amounts capitalized of $92 million, $83 million, and $78 million, respectively.

Impairment of Long-Lived Assets and Intangibles

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

Storm Damage Reserves

Each traditional operating company maintains a reserve to cover the cost of damages from major storms to its transmission and distribution lines and generally the cost of uninsured damages to its generation facilities and other property. In accordance with their respective state PSC orders, the traditional operating companies accrued $28 million in 2013 and 2012. Alabama Power, Gulf Power, and Mississippi Power also have authority based on orders from their state PSCs to accrue certain additional amounts as circumstances warrant. In 2013 and 2012, there were no such additional accruals. See Note 3 under "Retail Regulatory Matters – Alabama Power – Natural Disaster Reserve" for additional information regarding Alabama Power's natural disaster reserve.

Leveraged Leases

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

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

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

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

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

Cash and Cash Equivalents

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

Materials and Supplies

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

Fuel Inventory

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

Financial Instruments

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

The Company does not offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. At December 31, 2013, the amount included in accounts payable in the balance sheets that the Company has recognized for the obligation to return cash collateral arising from derivative instruments was immaterial.

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

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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 marketable securities, certain changes in pension and other postretirement benefit plans, reclassifications for amounts included in net income, and dividends on preferred and preference stock of subsidiaries.

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

	Qualifying Hedges	Marketable Securities	Pension and Other Postretirement Benefit Plans	Accumulated Other Comprehensive Income (Loss)
	(in millions)			
Balance at December 31, 2012	$(45)	$3	$(81)	$(123)
Current period change	9	(3)	42	48
Balance at December 31, 2013	$(36)	$—	$(39)	$(75)

2. RETIREMENT BENEFITS

Southern Company has a defined benefit, trusteed, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions were made to the qualified pension plan during 2013. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2014. Southern Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, Southern Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The traditional operating companies fund related other postretirement trusts to the extent required by their respective regulatory commissions. For the year ending December 31, 2014, other postretirement trust contributions are expected to total approximately $13 million.

Actuarial Assumptions

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

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

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

An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) was a weighted average medical care cost trend rate of 7.00% for 2014, decreasing gradually to 5.00% through the year 2021 and remaining at that level thereafter. An annual increase or decrease in the assumed medical care cost trend rate of 1% would affect the APBO and the service and interest cost components at December 31, 2013 as follows:

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

Pension Plans

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

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

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

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

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

Presented below are the amounts included in accumulated OCI and regulatory assets at December 31, 2013 and 2012 related to the defined benefit pension plans that had not yet been recognized in net periodic pension cost along with the estimated amortization of such amounts for 2014.

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

The components of OCI and the changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2013 and 2012 are presented in the following table:

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

Components of net periodic pension cost were as follows:

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

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

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2013, estimated benefit payments were as follows:

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

Other Postretirement Benefits

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

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

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

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

Presented below are the amounts included in accumulated OCI and net regulatory assets (liabilities) at December 31, 2013 and 2012 related to the other postretirement benefit plans that had not yet been recognized in net periodic other postretirement benefit cost along with the estimated amortization of such amounts for 2014.

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

The components of OCI, along with the changes in the balance of net regulatory assets (liabilities), related to the other postretirement benefit plans for the plan years ended December 31, 2013 and 2012 are presented in the following table:

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

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

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

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

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

Benefit Plan Assets

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

The composition of the Company's pension plan and other postretirement benefit plan assets as of December 31, 2013 and 2012, along with the targeted mix of assets for each plan, is presented below:

	Target		2013		2012	
Pension plan assets:						
Domestic equity	26	%	31	%	28	%
International equity	25		25		24	
Fixed income	23		23		27	
Special situations	3		1		1	
Real estate investments	14		14		13	
Private equity	9		6		7	
Total	100	%	100	%	100	%
Other postretirement benefit plan assets:						
Domestic equity	40	%	40	%	38	%
International equity	21		25		24	
Domestic fixed income	25		24		28	
Global fixed income	4		4		3	
Special situations	1		—		—	
Real estate investments	6		5		5	
Private equity	3		2		2	
Total	100	%	100	%	100	%

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

Investment Strategies

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

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

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

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

Benefit Plan Asset Fair Values

Following are the fair value measurements for the pension plan and the other postretirement benefit plan assets as of December 31, 2013 and 2012. The fair values presented are prepared in accordance with GAAP. For purposes of determining the fair value of the pension plan and other postretirement benefit plan assets and the appropriate level designation, management relies on information provided by the plan's trustee. This information is reviewed and evaluated by management with changes made to the trustee information as appropriate.

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

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

The fair values of pension plan assets as of December 31, 2013 and 2012 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments, primarily real estate investments and private equities, are presented in the tables below based on the nature of the investment.

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

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

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

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

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

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

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

The fair values of other postretirement benefit plan assets as of December 31, 2013 and 2012 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments, primarily real estate investments and private equities, are presented in the tables below based on the nature of the investment.

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

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

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

As of December 31, 2012:	Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1)	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.

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

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

Employee Savings Plan

Southern Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides an 85% matching contribution on up to 6% of an employee's base salary. Total matching contributions made to the plan for 2013, 2012, and 2011 were $84 million, $82 million, and $78 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

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

Insurance Recovery

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

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

Environmental Matters

New Source Review Actions

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

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

Environmental Remediation

The Southern Company system must comply with environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Southern Company system could incur substantial costs to clean up properties. The traditional operating companies have each received authority from their respective state PSCs to recover approved environmental compliance costs through regulatory mechanisms. These rates are adjusted annually or as necessary within limits approved by the state PSCs. Georgia Power's environmental remediation liability as of December 31, 2013 was $18 million. Georgia Power has been designated or identified as a potentially responsible party (PRP) at sites governed by the Georgia Hazardous Site Response Act and/or by the federal Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), including a site in

Brunswick, Georgia on the CERCLA National Priorities List (NPL). The parties have completed the removal of wastes from the Brunswick site as ordered by the EPA. Additional cleanup and claims for recovery of natural resource damages at this site or for the assessment and potential cleanup of other sites are anticipated.

Georgia Power and numerous other entities have been designated by the EPA as PRPs at the Ward Transformer Superfund site located in Raleigh, North Carolina. In 2011, the EPA issued a Unilateral Administrative Order (UAO) to Georgia Power and 22 other parties, ordering specific remedial action of certain areas at the site. Later in 2011, Georgia Power filed a response with the EPA stating it has sufficient cause to believe it is not a liable party under CERCLA. The EPA notified Georgia Power in 2011 that it is considering enforcement options against Georgia Power and other non-complying UAO recipients. If the EPA pursues enforcement actions and the court determines that a respondent failed to comply with the UAO without sufficient cause, the EPA may also seek civil penalties of up to $37,500 per day for the violation and punitive damages of up to three times the costs incurred by the EPA as a result of the party's failure to comply with the UAO.

In addition to the EPA's action at this site, Georgia Power, along with many other parties, was sued in a private action by several existing PRPs for cost recovery related to the removal action. On February 1, 2013, the U.S. District Court for the Eastern District of North Carolina Western Division granted Georgia Power's summary judgment motion, ruling that Georgia Power has no liability in the private action. On May 10, 2013, the plaintiffs appealed the U.S. District Court for the Eastern District of North Carolina Western Division's order to the U.S. Court of Appeals for the Fourth Circuit.

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

Gulf Power's environmental remediation liability includes estimated costs of environmental remediation projects of approximately $50 million as of December 31, 2013. These estimated costs relate to site closure criteria by the Florida Department of Environmental Protection (FDEP) for potential impacts to soil and groundwater from herbicide applications at Gulf Power substations. The schedule for completion of the remediation projects will be subject to FDEP approval. The projects have been approved by the Florida PSC for recovery through Gulf Power's environmental cost recovery clause; therefore, there was no impact on net income as a result of these liabilities.

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

Nuclear Fuel Disposal Costs

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

As a result of the first lawsuit, Georgia Power recovered approximately $27 million, based on its ownership interests, and Alabama Power recovered approximately $17 million, representing the vast majority of the Southern Company system's direct costs of the expansion of spent nuclear fuel storage facilities at Plants Farley and Hatch and Plant Vogtle Units 1 and 2 from 1998 through 2004. In April 2012, Alabama Power credited the award to cost of service for the benefit of customers. In July 2012, Georgia Power credited the award to accounts where the original costs were charged and used it to reduce rate base, fuel, and cost of service for the benefit of customers.

In 2008, Alabama Power and Georgia Power filed a second lawsuit against the U.S. government for the costs of continuing to store spent nuclear fuel at Plants Farley and Hatch and Plant Vogtle Units 1 and 2. Damages are being sought for the period from January 1, 2005 through December 31, 2010. Damages will continue to accumulate until the issue is resolved or storage is provided. No amounts have been recognized in the financial statements as of December 31, 2013 for any potential recoveries from the second lawsuit. The final outcome of these matters cannot be determined at this time; however, no material impact on Southern Company's net income is expected.

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

Retail Regulatory Matters

Alabama Power

Retail Rate Adjustments

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

Rate RSE

Alabama Power operates under a rate stabilization and equalization plan (Rate RSE) approved by the Alabama PSC. Alabama Power's Rate RSE adjustments are based on forward-looking information for the applicable upcoming calendar year. Rate adjustments for any two-year period, when averaged together, cannot exceed 4.0% and any annual adjustment is limited to 5.0%. If Alabama Power's actual retail return is above the allowed equity return range, customer refunds will be required; however, there is no provision for additional customer billings should the actual retail return fall below the allowed equity return range. Prior to 2014, retail rates remained unchanged when the retail return on common equity (ROE) was projected to be between 13.0% and 14.5%.

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

- Eliminate the provision of Rate RSE establishing an allowed range of ROE.
- Eliminate the provision of Rate RSE limiting Alabama Power's capital structure to an allowed equity ratio of 45%.
- Replace these two provisions with a provision that establishes rates based upon an allowed weighted cost of equity (WCE) range of 5.75% to 6.21%, with an adjusting point of 5.98%. If calculated under the previous Rate RSE provisions, the resulting WCE would range from 5.85% to 6.53%, with an adjusting point of 6.19%.
- Provide eligibility for a performance-based adder of seven basis points, or 0.07%, to the WCE adjusting point if Alabama Power (i) has an "A" credit rating equivalent with at least one of the recognized rating agencies or (ii) is in the top one-third of a designated customer value benchmark survey.

Substantially all other provisions of Rate RSE were unchanged.

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

Rate CNP

Alabama Power's retail rates, approved by the Alabama PSC, provide for adjustments to recognize the placing of new generating facilities into retail service under rate certificated new plant (Rate CNP). Alabama Power may also recover retail costs associated with certificated PPAs under rate certificated new plant (Rate CNP PPA). There was no adjustment to Rate CNP PPA in 2012. On March 5, 2013, the Alabama PSC issued a consent order that Alabama Power leave in effect the current Rate CNP PPA factor for billings for the period April 1, 2013 through March 31, 2014. It is anticipated that no adjustment will be made to Rate CNP PPA in 2014. As of December 31, 2013, Alabama Power had an under recovered certificated PPA balance of $18 million, all of which is included in deferred under recovered regulatory clause revenues in the balance sheet.

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

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

Environmental Accounting Order

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

Compliance and Pension Cost Accounting Order

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

Retail Energy Cost Recovery

Alabama Power has established energy cost recovery rates under Alabama Power's energy cost recovery rate (Rate ECR) as approved by the Alabama PSC. Rates are based on an estimate of future energy costs and the current over or under recovered balance. Revenues recognized under Rate ECR and recorded on the financial statements are adjusted for the difference in actual recoverable fuel costs and amounts billed in current regulated rates. The difference in the recoverable fuel costs and amounts billed give rise to the over or under recovered amounts recorded as regulatory assets or liabilities. Alabama Power, along with the Alabama PSC, continually monitors the over or under recovered cost balance to determine whether an adjustment to billing rates is required. Changes in the Rate ECR factor have no significant effect on net income, but will impact operating cash flows. Currently, the Alabama PSC may approve billing rates under Rate ECR of up to 5.910 cents per kilowatt hour (KWH). On December 3, 2013, the Alabama PSC issued a consent order that Alabama Power leave in effect the energy cost recovery rates which began in April 2011 for 2014. Therefore, the Rate ECR factor as of January 1, 2014 remained at 2.681 cents per KWH. Effective with billings beginning in January 2015, the Rate ECR factor will be 5.910 cents per KWH, absent a further order from the Alabama PSC.

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

Natural Disaster Reserve

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

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

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

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

Nuclear Outage Accounting Order

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

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

Non-Nuclear Outage Accounting Order

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

Georgia Power

Rate Plans

In 2010, the Georgia PSC approved the 2010 ARP, which resulted in base rate increases of approximately $562 million, $17 million, $125 million, and $74 million effective January 1, 2011, January 1, 2012, April 1, 2012, and January 1, 2013, respectively.

On December 17, 2013, the Georgia PSC voted to approve the 2013 ARP. The 2013 ARP reflects the settlement agreement among Georgia Power, the Georgia PSC's Public Interest Advocacy Staff, and 11 of the 13 intervenors, which was filed with the Georgia PSC on November 18, 2013.

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

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

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

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

Under the 2013 ARP, Georgia Power's retail ROE is set at 10.95%, and earnings are evaluated against a retail ROE range of 10.00% to 12.00%. Two-thirds of any earnings above 12.00% will be directly refunded to customers, with the remaining one-third retained by Georgia Power. There will be no recovery of any earnings shortfall below 10.00% on an actual basis. However, if at any time during the term of the 2013 ARP, Georgia Power projects that its retail earnings will be below 10.00% for any calendar year, it may petition the Georgia PSC for implementation of the Interim Cost Recovery (ICR) tariff that would be used to adjust Georgia Power's earnings back to a 10.00% retail ROE. The Georgia PSC would have 90 days to rule on Georgia Power's request. The ICR tariff will expire at the earlier of January 1, 2017 or the end of the calendar year in which the ICR tariff becomes effective. In lieu of requesting implementation of an ICR tariff, or if the Georgia PSC chooses not to implement the ICR tariff, Georgia Power may file a full rate case.

Except as provided above, Georgia Power will not file for a general base rate increase while the 2013 ARP is in effect. Georgia Power is required to file a general rate case by July 1, 2016, in response to which the Georgia PSC would be expected to determine whether the 2013 ARP should be continued, modified, or discontinued.

Integrated Resource Plans

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

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

Multi-Pollutant Rule.
On July 11, 2013, the Georgia PSC approved Georgia Power's request to decertify and retire Plant Boulevard Units 2 and 3 (28 MWs) effective July 17, 2013. Plant Branch Units 3 and 4 (1,016 MWs), Plant Yates Units 1 through 5 (579 MWs), and Plant McManus Units 1 and 2 (122 MWs) will be decertified and retired by April 16, 2015, the compliance date of the Mercury and Air Toxics Standards (MATS) rule. The decertification date of Plant Branch Unit 1 was extended from December 31, 2013 as

specified in the final order in the 2011 IRP Update to coincide with the decertification date of Plant Branch Units 3 and 4. The decertification and retirement of Plant Kraft Units 1 through 4 (316 MWs) was also approved and will be effective by April 16, 2016, based on a one-year extension of the MATS rule compliance date that was approved by the State of Georgia Environmental Protection Division on September 10, 2013 to allow for necessary transmission system reliability improvements.

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

In the 2013 ARP, the Georgia PSC approved the amortization of the construction work in progress (CWIP) balances related to environmental projects that will not be completed at Plant Branch Units 1 through 4 and Plant Yates Units 6 and 7 over nine years beginning in January 2014 and the amortization of any remaining net book values of Plant Branch Unit 2 from October 2013 to December 2022, Plant Branch Unit 1 from May 2015 to December 2020, Plant Branch Unit 3 from May 2015 to December 2023, and Plant Branch Unit 4 from May 2015 to December 2024. The Georgia PSC deferred a decision regarding the appropriate recovery period for the costs associated with unusable materials and supplies remaining at the retiring plants to Georgia Power's next base rate case, which Georgia Power expects to file in 2016 (2016 Rate Case). In the 2013 IRP, the Georgia PSC also deferred decisions regarding the recovery of any fuel related costs that could be incurred in connection with the retirement units to be addressed in future fuel cases.

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

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

Renewables Development

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

On November 4, 2013, Georgia Power filed an application for the certification of two PPAs which were executed on April 22, 2013 for the purchase of energy from two wind farms in Oklahoma with capacity totaling 250 MWs that will begin in 2016 and end in 2035.

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

Fuel Cost Recovery

Georgia Power has established fuel cost recovery rates approved by the Georgia PSC. The Georgia PSC approved reductions in Georgia Power's total annual billings of approximately $43 million effective June 1, 2011, $567 million effective June 1, 2012, and $122 million effective January 1, 2013. The 2013 reduction was due to the Georgia PSC authorizing an Interim Fuel Rider, which is set to expire June 1, 2014. Georgia Power continues to be allowed to adjust its fuel cost recovery rates prior to the next fuel case if the under or over recovered fuel balance exceeds $200 million. Georgia Power's fuel cost recovery includes costs associated with a natural gas hedging program as revised and approved by the Georgia PSC on February 7, 2013, requiring it to use options and hedges within a 24-month time horizon. On February 18, 2014, the Georgia PSC approved the deferral of Georgia Power's next fuel case, which is now expected to be filed by March 1, 2015.

Georgia Power's over recovered fuel balance totaled approximately $58 million and $230 million at December 31, 2013 and 2012, respectively, and is included in current liabilities and other deferred credits and liabilities.

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

Storm Damage Recovery

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

Nuclear Construction

In 2008, Georgia Power, acting for itself and as agent for Oglethorpe Power Corporation (OPC), the Municipal Electric Authority of Georgia (MEAG Power), and the City of Dalton, Georgia (Dalton), acting by and through its Board of Water, Light, and Sinking Fund Commissioners (collectively, Owners), entered into an agreement with a consortium consisting of Westinghouse Electric Company LLC (Westinghouse) and Stone & Webster, Inc. (collectively, Contractor), pursuant to which the Contractor agreed to design, engineer, procure, construct, and test two AP1000 nuclear units (with electric generating capacity of approximately 1,100 MWs each) and related facilities at Plant Vogtle (Vogtle 3 and 4 Agreement). Under the terms of the Vogtle 3 and 4 Agreement, the Owners agreed to pay a purchase price that is subject to certain price escalations and adjustments, including fixed escalation amounts and index-based adjustments, as well as adjustments for change orders, and performance bonuses for early completion and unit performance. Each Owner is severally (and not jointly) liable for its proportionate share, based on its ownership interest, of all amounts owed to the Contractor under the Vogtle 3 and 4 Agreement. Georgia Power's proportionate share is 45.7%. The Vogtle 3 and 4 Agreement provides for liquidated damages upon the Contractor's failure to fulfill the schedule and performance guarantees. The Contractor's liability to the Owners for schedule and performance liquidated damages and warranty claims is subject to a cap.

Certain payment obligations of Westinghouse and Stone & Webster, Inc. under the Vogtle 3 and 4 Agreement are guaranteed by Toshiba Corporation and The Shaw Group, Inc., respectively. In the event of certain credit rating downgrades of any Owner, such Owner will be required to provide a letter of credit or other credit enhancement. The Owners may terminate the Vogtle 3 and 4 Agreement at any time for their convenience, provided that the Owners will be required to pay certain termination costs. The Contractor may terminate the Vogtle 3 and 4 Agreement under certain circumstances, including certain Owner suspension or delays of work, action by a governmental authority to permanently stop work, certain breaches of the Vogtle 3 and 4 Agreement by the Owners, Owner insolvency, and certain other events.

In 2009, the NRC issued an Early Site Permit and Limited Work Authorization which allowed limited work to begin on Plant Vogtle Units 3 and 4. The NRC certified the Westinghouse Design Control Document, as amended (DCD), for the AP1000 nuclear reactor design, effective December 30, 2011, and issued combined construction and operating licenses (COLs) in February 2012. Receipt of the COLs allowed full construction to begin. There have been technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4, at the federal and state level, and additional challenges are expected as construction proceeds.

In 2009, the Georgia PSC approved inclusion of the construction of two new nuclear generating units at Plant Vogtle (Plant Vogtle Units 3 and 4) related CWIP accounts in rate base, and the State of Georgia enacted the Georgia Nuclear Energy Financing Act, which allows Georgia Power to recover financing costs for nuclear construction projects certified by the Georgia PSC. Financing costs are recovered on all applicable certified costs through annual adjustments to the Nuclear Construction Cost Recovery (NCCR) tariff by including the related CWIP accounts in rate base during the construction period. The Georgia PSC approved increases to the NCCR tariff of approximately $223 million, $35 million, $50 million, and $60 million, effective January 1, 2011, 2012, 2013, and 2014, respectively. Through the NCCR tariff, Georgia Power is collecting and amortizing to earnings approximately $91 million of financing costs, capitalized in 2009 and 2010, over the five-year period ending December 31, 2015, in addition to the ongoing financing costs. At December 31, 2013, approximately $37 million of these 2009 and 2010 costs remained unamortized in CWIP.

Georgia Power is required to file semi-annual Vogtle Construction Monitoring (VCM) reports with the Georgia PSC by February 28 and August 31 each year. If the projected certified construction capital costs to be borne by Georgia Power increase by 5% or the projected in-service dates are significantly extended, Georgia Power is required to seek an amendment to the Plant Vogtle Units 3 and 4 certificate from the Georgia PSC. Accordingly, Georgia Power's eighth VCM report requested an amendment to the certificate to increase the estimated in-service capital cost of Plant Vogtle Units 3 and 4 from $4.4 billion to $4.8 billion and to extend the estimated in-service dates to the fourth quarter 2017 and the fourth quarter 2018 for Plant Vogtle Units 3 and 4, respectively.

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

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

Processes are in place that are designed to assure compliance with the requirements specified in the DCD and the COLs, including inspections by Southern Nuclear and the NRC that occur throughout construction. As a result of such compliance processes, certain license amendment requests have been filed and approved or are pending before the NRC. Various design and other licensing-based compliance issues are expected to arise as construction proceeds, which may result in additional license amendments or require other resolution. If any license amendment requests or other licensing-based compliance issues are not resolved in a timely manner, there may be delays in the project schedule that could result in increased costs either to the Owners, the Contractor, or both.

As construction continues, the risk remains that additional challenges in the fabrication, assembly, delivery, and installation of structural modules, delays in the receipt of the remaining permits necessary for the operation of Plant Vogtle Units 3 and 4, or other issues could arise and may further impact project schedule and cost. Additional claims by the Contractor or Georgia Power (on behalf of the Owners) are also likely to arise throughout construction. These claims may be resolved through formal and informal dispute resolution procedures under the Vogtle 3 and 4 Agreement, but also may be resolved through litigation.

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

Gulf Power

Retail Base Rate Case

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

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

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

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

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

Integrated Coal Gasification Combined Cycle

Kemper IGCC Overview

Construction of Mississippi Power's Kemper IGCC is nearing completion and start-up activities will continue until the Kemper IGCC is placed in service. The Kemper IGCC will utilize an integrated coal gasification combined cycle technology with an output capacity of 582 MWs. The Kemper IGCC will be fueled by locally mined lignite (an abundant, lower heating value coal) from a mine owned by Mississippi Power and situated adjacent to the Kemper IGCC. The mine, operated by North American Coal Corporation, started commercial operation on June 5, 2013. In connection with the Kemper IGCC, Mississippi Power constructed and plans to operate approximately 61 miles of CO_2 pipeline infrastructure for the planned transport of captured CO_2 for use in enhanced oil recovery.

Kemper IGCC Project Approval

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

Kemper IGCC Schedule and Cost Estimate

The certificated cost estimate of the Kemper IGCC included in the 2012 MPSC CPCN Order was $2.4 billion, net of $245 million of grants awarded to the project by the DOE under the Clean Coal Power Initiative Round 2 (DOE Grants) and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, and AFUDC related to the Kemper IGCC. The 2012 MPSC CPCN Order approved a construction cost cap of up to $2.88 billion, with recovery of prudently-incurred costs subject to approval by the Mississippi PSC. Exceptions to the $2.88 billion cost cap include the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, AFUDC, and certain general exceptions, including change of law, force majeure, and beneficial capital (which exists when Mississippi Power demonstrates that the purpose and effect of the construction cost increase is to produce efficiencies that will result in a neutral or favorable effect on the ratepayers, relative to the original proposal for the CPCN) (Cost Cap Exceptions), as contemplated in the settlement agreement between Mississippi Power and the Mississippi PSC entered into on January 24, 2013 (Settlement Agreement) and the 2012 MPSC CPCN Order. Recovery of the Cost Cap Exception amounts remains subject to review and approval by the Mississippi PSC. The Kemper IGCC was originally scheduled to be placed in service in May 2014 and is currently scheduled to be placed in service in the fourth quarter 2014.

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

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

(a) The 2012 MPSC CPCN Order approved a construction cost cap of up to $2.88 billion, net of the DOE Grants and excluding the Cost Cap Exceptions.

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

(c) The 2012 MPSC CPCN Order approved deferral of non-capital Kemper IGCC-related costs during construction as described in "Rate Recovery of Kemper IGCC Costs – Regulatory Assets."

(d) The 2010 Project Estimate is the certificated cost estimate adjusted to include the certificated estimate for the CO_2 pipeline facilities which was approved in 2011 by the Mississippi PSC.

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

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

Mississippi Power could experience further construction cost increases and/or schedule extensions with respect to the Kemper IGCC as a result of factors including, but not limited to, labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, or non-performance under construction or other agreements. Furthermore, Mississippi Power could also experience further schedule extensions associated with start-up activities for this "first-of-a-kind" technology, including major equipment failure, system integration, and operations, and/or unforeseen engineering problems, which would result in further cost increases and could result in the loss of certain tax benefits related to bonus depreciation. In subsequent periods, any further changes in the estimated costs to complete construction of the Kemper IGCC subject to the $2.88 billion cost cap will be reflected in Southern Company's statements of income and these changes could be material.

Rate Recovery of Kemper IGCC Costs

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

2012 MPSC CPCN Order

The 2012 MPSC CPCN Order included provisions relating to both Mississippi Power's recovery of financing costs during the course of construction of the Kemper IGCC and Mississippi Power's recovery of costs following the date the Kemper IGCC is placed in service. With respect to recovery of costs following the in-service date of the Kemper IGCC, the 2012 MPSC CPCN Order provided for the establishment of operational cost and revenue parameters based upon assumptions in Mississippi Power's petition for the CPCN.

In June 2012, the Mississippi PSC denied Mississippi Power's proposed rate schedule for recovery of financing costs during construction, pending a final ruling from the Mississippi Supreme Court regarding the Sierra Club's appeal of the Mississippi PSC's issuance of the CPCN for the Kemper IGCC (2012 MPSC CWIP Order).
In July 2012, Mississippi Power appealed the Mississippi PSC's June 2012 decision to the Mississippi Supreme Court and requested interim rates under bond. In July 2012, the Mississippi Supreme Court denied Mississippi Power's request for interim rates under bond.

Settlement Agreement

On January 24, 2013, Mississippi Power entered into the Settlement Agreement with the Mississippi PSC that, among other things, establishes the process for resolving matters regarding cost recovery related to the Kemper IGCC and dismissed Mississippi Power's appeal of the 2012 MPSC CWIP Order. Under the Settlement Agreement, Mississippi Power agreed to limit the portion of prudently-incurred Kemper IGCC costs to be included in retail rate base to the $2.4 billion certificated cost estimate, plus the Cost Cap Exceptions, but excluding AFUDC, and any other costs permitted or determined to be excluded from the $2.88 billion cost cap by the Mississippi PSC. The Settlement Agreement also allows Mississippi Power to secure alternate financing for costs that are not otherwise recovered in any Mississippi PSC rate proceedings contemplated by the Settlement Agreement. Legislation to authorize a multi-year rate plan and legislation to provide for alternate financing through securitization of up to $1.0 billion of prudently-incurred costs was enacted into law on February 26, 2013. Mississippi Power intends to securitize (1) prudently-incurred costs in excess of the certificated cost estimate and up to the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions, (2) accrued AFUDC, and (3) other prudently-incurred costs as approved by the Mississippi PSC. The rate recovery necessary to recover the annual costs of securitization is expected to be filed and become effective after the Kemper IGCC is placed in service and following completion of the Mississippi PSC's final prudence review of costs for the Kemper IGCC.
The Settlement Agreement provides that Mississippi Power may terminate the Settlement Agreement if certain conditions are not met, if Mississippi Power is unable to secure alternate financing for any prudently-incurred Kemper IGCC costs not otherwise recovered in any Mississippi PSC rate proceeding contemplated by the Settlement Agreement, or if the Mississippi PSC fails to comply with the requirements of the Settlement Agreement. Mississippi Power continues to work with the Mississippi PSC and the Mississippi Public Utilities Staff to implement the procedural schedules set forth in the Settlement Agreement and variations to the schedule are likely.

2013 MPSC Rate Order

Consistent with the terms of the Settlement Agreement, on January 25, 2013, Mississippi Power filed a new request to increase retail rates in 2013 by $172 million annually, based on projected investment for 2013, to be recorded to a regulatory liability to be used to mitigate rate impacts when the Kemper IGCC is placed in service.
On March 5, 2013, the Mississippi PSC issued an order (2013 MPSC Rate Order) approving retail rate increases of 15% effective March 19, 2013 and 3% effective January 1, 2014, which collectively are designed to collect $156 million annually beginning in 2014. Amounts collected through these rates are being recorded as a regulatory liability to be used to mitigate customer rate impacts after the Kemper IGCC is placed in service. As of December 31, 2013, $98.1 million had been collected, with $10.3 million recognized in retail revenues in the statement of income and the remainder deferred in other regulatory liabilities and included in the balance sheet.
Because the 2013 MPSC Rate Order did not provide for the inclusion of CWIP in rate base as permitted by legislation designed to enhance the Mississippi PSC's authority to facilitate development and construction of baseload generation in the State of Mississippi (Baseload Act), Mississippi Power continues to record AFUDC on the Kemper IGCC during the construction period. Mississippi Power will not record AFUDC on any additional costs of the Kemper IGCC that exceed the $2.88 billion cost cap, except for Cost Cap Exception amounts. Mississippi Power will continue to comply with the 2013 MPSC Rate Order by collecting and deferring the approved rates during the construction period unless directed to do otherwise by the Mississippi PSC. On March 21, 2013, a legal challenge to the 2013 MPSC Rate Order was filed by Thomas A. Blanton with the Mississippi Supreme Court, which remains pending against Mississippi Power and the Mississippi PSC.

Seven-Year Rate Plan

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

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

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

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

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

Prudence Reviews

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

Regulatory Assets

Consistent with the treatment of non-capital costs incurred during the pre-construction period, the Mississippi PSC granted Mississippi Power the authority to defer all non-capital Kemper IGCC-related costs to a regulatory asset during the construction period, subject to review of such costs by the Mississippi PSC. The amortization period for any such costs approved for recovery will be determined by the Mississippi PSC at a later date. In addition, Mississippi Power is authorized to accrue carrying costs on the unamortized balance of such regulatory assets at a rate and in a manner to be determined by the Mississippi PSC in future cost recovery mechanism proceedings.

Lignite Mine and CO_2 Pipeline Facilities

In conjunction with the Kemper IGCC, Mississippi Power will own the lignite mine and equipment and has acquired and will continue to acquire mineral reserves located around the Kemper IGCC site. The mine started commercial operation on June 5, 2013.

In 2010, Mississippi Power executed a 40-year management fee contract with Liberty Fuels Company, LLC, a wholly-owned subsidiary of The North American Coal Corporation (Liberty Fuels), which will develop, construct, and manage the mining operations. The contract with Liberty Fuels is effective through the end of the mine reclamation. As the mining permit holder, Liberty Fuels has a legal obligation to perform mine reclamation and Mississippi Power has a contractual obligation to fund all reclamation activities. In addition to the obligation to fund the reclamation activities, Mississippi Power currently provides working capital support to Liberty Fuels through cash advances for capital purchases, payroll, and other operating expenses. See Note 1 under "Asset Retirement Obligations and Other Costs of Removal" for additional information.

In addition, Mississippi Power will acquire, construct, and operate the CO_2 pipeline for the planned transport of captured CO_2 for use in enhanced oil recovery. Mississippi Power has entered into agreements with Denbury Onshore (Denbury), a subsidiary of Denbury Resources Inc., and Treetop Midstream Services, LLC (Treetop), an affiliate of Tellus Operating Group, LLC and a subsidiary of Tengrys, LLC, pursuant to which Denbury will purchase 70% of the CO_2 captured from the Kemper IGCC and Treetop will purchase 30% of the CO_2 captured from the Kemper IGCC. The ultimate outcome of these matters cannot be determined at this time.

Proposed Sale of Undivided Interest to SMEPA

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

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

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

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

Baseload Act

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

Investment Tax Credits and Bonus Depreciation

The IRS allocated $133 million (Phase I) and $279 million (Phase II) of Internal Revenue Code Section 48A tax credits to Mississippi Power in connection with the Kemper IGCC. On May 15, 2013, the IRS notified Mississippi Power that no additional tax credits under the Internal Revenue Code Section 48A Phase III were allocated to the Kemper IGCC. As a result of the schedule extension for the Kemper IGCC, the Phase I credits have been recaptured. Through December 31, 2013, Mississippi Power had recorded tax benefits totaling $276.4 million for the remaining Phase II credits, which will be amortized as a reduction to depreciation and amortization over the life of the Kemper IGCC and are dependent upon meeting the IRS certification requirements, including an in-service date no later than April 19, 2016 and the capture and sequestration (via enhanced oil recovery) of at least 65% of the CO_2 produced by the Kemper IGCC during operations in accordance with the Internal Revenue Code. A portion of the Phase II tax credits will be subject to recapture upon successful completion of SMEPA's purchase of an undivided interest in the Kemper IGCC as described above.

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

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

4. JOINT OWNERSHIP AGREEMENTS

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

At December 31, 2013, Alabama Power's, Georgia Power's, and Southern Power's percentage ownership and investment (exclusive of nuclear fuel) in jointly-owned facilities in commercial operation with the above entities were as follows:

Facility (Type)	Percent Ownership		Plant in Service	Accumulated Depreciation	CWIP
			(in millions)		
Plant Vogtle (nuclear) Units 1 and 2	45.7	%	$3,375	$2,028	$53
Plant Hatch (nuclear)	50.1		1,092	551	52
Plant Miller (coal) Units 1 and 2	91.8		1,410	575	89
Plant Scherer (coal) Units 1 and 2	8.4		209	80	24
Plant Wansley (coal)	53.5		800	260	36
Rocky Mountain (pumped storage)	25.4		182	120	—
Intercession City (combustion turbine)	33.3		14	4	—
Plant Stanton (combined cycle) Unit A	65.0		156	42	—

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

Alabama Power, Georgia Power, and Southern Power have contracted to operate and maintain the jointly-owned facilities, except for Rocky Mountain and Intercession City, as agents for their respective co-owners. The companies' proportionate share of their plant operating expenses is included in the corresponding operating expenses in the statements of income and each company is responsible for providing its own financing.

5. INCOME TAXES

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

Current and Deferred Income Taxes

Details of income tax provisions are as follows:

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

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

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

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

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

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

At December 31, 2013, the tax-related regulatory assets to be recovered from customers were $1.4 billion. These assets are primarily attributable to tax benefits flowed through to customers in prior years, deferred taxes previously recognized at rates lower than the current enacted tax law, and taxes applicable to capitalized interest.

At December 31, 2013, the tax-related regulatory liabilities to be credited to customers were $202 million. These liabilities are primarily attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and to unamortized ITCs.

In accordance with regulatory requirements, deferred federal ITCs are amortized over the life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $16 million in 2013, $23 million in 2012, and $19 million in 2011. At December 31, 2013, all ITCs available to reduce federal income taxes payable had not been utilized. The remaining ITCs will be carried forward and utilized in future years.

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

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

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

Effective Tax Rate

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

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

Southern Company's effective tax rate is typically lower than the statutory rate due to its employee stock plans' dividend deduction and non-taxable AFUDC equity. Additionally, the 2013 effective rate decrease, as compared to 2012, is primarily due to an increase in non-taxable AFUDC equity. No material change occurred in the effective tax rate from 2011 to 2012.

Unrecognized Tax Benefits

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

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

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

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

	2013	2012	2011
	(in millions)		
Tax positions impacting the effective tax rate	$7	$5	$69
Tax positions not impacting the effective tax rate	—	65	51
Balance of unrecognized tax benefits	$7	$70	$120

The tax positions impacting the effective tax rate for 2013 primarily relate to state income tax credits. These amounts are presented on a gross basis without considering the related federal or state income tax impact.

Accrued interest for unrecognized tax benefits was as follows:

	2013	2012	2011
	(in millions)		
Interest accrued at beginning of year	$1	$10	$29
Interest reclassified due to settlements	—	(9)	(24)
Interest accrued during the year	—	—	5
Balance at end of year	$1	$1	$10

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

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

The IRS has finalized its audits of Southern Company's consolidated federal income tax returns through 2011. Southern Company has filed its 2012 federal income tax return and has received a full acceptance letter from the IRS; however, the IRS has not finalized its audit. For tax years 2012 and 2013, Southern Company was a participant in the Compliance Assurance Process of the IRS. The audits for Southern Company's state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2007.

Tax Method of Accounting for Repairs

In 2011, the IRS published regulations on the deduction and capitalization of expenditures related to tangible property that generally apply for tax years beginning on or after January 1, 2014. Additionally, on April 30, 2013, the IRS issued Revenue Procedure 2013-24, which provides guidance for taxpayers related to the deductibility of repair costs associated with generation assets. Based on a review of the regulations, Southern Company incorporated provisions related to repair costs for generation assets into its consolidated 2012 federal income tax return and reversed all related unrecognized tax positions. On September 19, 2013, the IRS issued Treasury Decision 9636, "Guidance Regarding Deduction and Capitalization of Expenditures Related to Tangible Property," which are final tangible property regulations applicable to taxable years beginning on or after January 1, 2014. Southern Company is currently reviewing this new guidance. The ultimate outcome of this matter cannot be determined at this time; however, these regulations are not expected to have a material impact on the Company's financial statements.

6. FINANCING

Long-Term Debt Payable to an Affiliated Trust

Alabama Power has formed a wholly-owned trust subsidiary for the purpose of issuing preferred securities. The proceeds of the related equity investments and preferred security sales were loaned back to Alabama Power through the issuance of junior subordinated notes totaling $206 million as of December 31, 2013 and 2012, which constitute substantially all of the assets of this trust and are reflected in the balance sheets as long-term debt payable. Alabama Power considers that the mechanisms and obligations relating to the preferred securities issued for its benefit, taken together, constitute a full and unconditional guarantee by it of the trust's payment obligations with respect to these securities. At each of December 31, 2013 and 2012, trust preferred securities of $200 million were outstanding.

Securities Due Within One Year

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

	2013	2012
	(in millions)	
Senior notes	$428	$2,085
Other long-term debt	12	227
Capitalized leases	29	23
Total	$469	$2,335

Maturities through 2018 applicable to total long-term debt are as follows: $469 million in 2014; $2.97 billion in 2015; $1.83 billion in 2016; $1.14 billion in 2017; and $880 million in 2018.

Bank Term Loans

Certain of the traditional operating companies have entered into various floating rate bank term loan agreements for loans bearing interest based on one-month London Interbank Offered Rate (LIBOR). At December 31, 2013, Georgia Power had outstanding bank term loans totaling $400 million, which are reflected in notes payable on the balance sheets. Also at December 31, 2013, Mississippi Power had outstanding bank term loans totaling $525 million, which are reflected in the statements of capitalization as long-term debt. At December 31, 2012, Mississippi Power had outstanding bank term loans totaling $175 million.

During 2013, the traditional operating companies repaid approximately $550 million of floating rate bank notes bearing interest based on one-month LIBOR.

During 2012, Mississippi Power entered into a 366-day $100 million aggregate principal amount floating rate bank loan bearing interest based on one-month LIBOR. The first advance in the amount of $50 million was made in November 2012. In January 2013, the second advance in the amount of $50 million was made. In September 2013, Mississippi Power amended the bank loan, which extended the maturity date to 2015. The proceeds of this loan were used for working capital and for other general corporate purposes, including Mississippi Power's continuous construction program.

In March 2013, Mississippi Power entered into four two-year floating rate bank loans bearing interest based on one-month LIBOR. These term loans were for an aggregate principal amount of $300 million and proceeds were used for working capital and other general corporate purposes, including Mississippi Power's continuous construction program.

In September 2013, Mississippi Power entered into a two-year floating rate bank loan bearing interest based on one-month LIBOR. The term loan was for $125 million aggregate principal amount and proceeds were used to repay at maturity a two-year floating rate bank loan in the aggregate principal amount of $125 million.

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

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

These bank loans have covenants that limit debt levels to 65% of total capitalization, as defined in the agreements. For purposes of these definitions, debt excludes the long-term debt payable to affiliated trusts and other hybrid securities and, for Mississippi Power, securitized debt relating to the securitization of certain costs of the Kemper IGCC. At December 31, 2013, Georgia Power and Mississippi Power were in compliance with their respective debt limits.

DOE Loan Guarantee Borrowings

Pursuant to the loan guarantee program established under Title XVII of the Energy Policy Act of 2005 (Title XVII Loan Guarantee Program), Georgia Power and the DOE entered into a loan guarantee agreement (Loan Guarantee

Agreement) on February 20, 2014, under which the DOE agreed to guarantee the obligations of Georgia Power under a note purchase agreement (FFB Note Purchase Agreement) among the DOE, Georgia Power, and the Federal Financing Bank (FFB) and a related promissory note (FFB Promissory Note). The FFB Note Purchase Agreement and the FFB Promissory Note provide for a multi-advance term loan facility (FFB Credit Facility), under which Georgia Power may make term loan borrowings through the FFB.

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

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

Advances may be requested under the FFB Credit Facility on a quarterly basis through December 31, 2020. The final maturity date for each advance under the FFB Credit Facility is February 20, 2044. Interest is payable quarterly and principal payments will begin on February 20, 2020. Borrowings under the FFB Credit Facility will bear interest at the applicable U.S. Treasury rate plus a spread equal to 0.375%.

On February 20, 2014, Georgia Power made initial borrowings under the FFB Credit Facility in an aggregate principal amount of $1.0 billion. The interest rate applicable to $500 million of the initial advance under the FFB Credit Facility is 3.860% for an interest period that extends to February 20, 2044 (the final maturity date) and the interest rate applicable to the remaining $500 million is 3.488% for an interest period that extends to February 20, 2029, and will be reset from time to time thereafter through the final maturity date. In connection with its entry into the Loan Guarantee Agreement, the FFB Note Purchase Agreement, and the FFB Promissory Note, Georgia Power incurred issuance costs of approximately $67 million, which will be amortized over the life of the borrowings under the FFB Credit Facility.

Future advances are subject to satisfaction of customary conditions, as well as certification of compliance with the requirements of the Title XVII Loan Guarantee Program, including accuracy of project-related representations and warranties, delivery of updated project-related information, and evidence of compliance with the prevailing wage requirements of the Davis-Bacon Act of 1931, as amended, compliance with the Cargo Preference Act of 1954, and certification from the DOE's consulting engineer that proceeds of the advances are used to reimburse Eligible Project Costs.

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

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

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

Senior Notes

Southern Company and its subsidiaries issued a total of $2.1 billion of senior notes in 2013. Southern Company issued $500 million and its subsidiaries issued a total of $1.6 billion. The proceeds of these issuances were used to repay long-term indebtedness, to repay short-term indebtedness, and for other general corporate purposes, including the applicable subsidiaries' continuous construction programs.

At December 31, 2013 and 2012, Southern Company and its subsidiaries had a total of $17.3 billion and $17.4 billion, respectively, of senior notes outstanding. At December 31, 2013 and 2012, Southern Company had a total of $1.8 billion and $1.3 billion, respectively, of senior notes outstanding.

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

Pollution Control Revenue Bonds

Pollution control obligations represent loans to the traditional operating companies from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control and solid waste disposal facilities. In some cases, the pollution control obligations represent obligations under installment sales agreements with respect to facilities constructed with the proceeds of pollution control bonds issued by public authorities. The traditional operating companies had $3.2 billion and $3.4 billion of outstanding pollution control revenue bonds at December 31, 2013 and 2012, respectively. The traditional operating companies are required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. Proceeds from certain issuances are restricted until qualifying expenditures are incurred.

Plant Daniel Revenue Bonds

In 2011, in connection with Mississippi Power's election under its operating lease of Plant Daniel Units 3 and 4 to purchase the assets, Mississippi Power assumed the obligations of the lessor related to $270 million aggregate principal amount of Mississippi Business Finance Corporation Taxable Revenue Bonds, 7.13% Series 1999A due October 21, 2021, issued for the benefit of the lessor. See "Assets Subject to Lien" herein for additional information.

Other Revenue Bonds

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

In March 2013 and July 2013, the Mississippi Business Finance Corporation (MBFC) issued $15.8 million and $15.3 million, respectively, aggregate principal amount of MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2012A. The proceeds were used to reimburse Mississippi Power for the cost of the acquisition, construction, equipping, installation, and improvement of certain equipment and facilities for the lignite mining facility related to the Kemper IGCC. In September 2013, the MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2012A of $40.07 million, Series 2012B of $21.25 million, and Series 2012C of $21.25 million were paid at maturity.

In November 2013, the MBFC entered into an agreement to issue up to $33.75 million aggregate principal amount of MBFC Taxable Revenue Bonds, Series 2013A (Mississippi Power Company Project) and up to $11.25 million aggregate principal amount of MBFC Taxable Revenue Bonds, Series 2013B (Mississippi Power Company Project) for the benefit of Mississippi Power. In November 2013, the MBFC issued $11.25 million aggregate principal amount of MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2013B for the benefit of Mississippi Power. The proceeds were used to reimburse Mississippi Power for the cost of the acquisition, construction, equipping, installation, and improvement of certain equipment and facilities for the lignite mining facility related to the Kemper IGCC. Any future issuances of the Series 2013A bonds will be used for this same purpose.

Mississippi Power had $50.0 million of such obligations outstanding related to tax-exempt revenue bonds at December 31, 2013 and 2012 and $11.3 million and $51.5 million of such obligations related to taxable revenue bonds outstanding at December 31, 2013 and 2012, respectively. Such amounts are reflected in the statements of capitalization as long-term senior notes and debt.

Capital Leases

In September 2013, Mississippi Power entered into a nitrogen supply agreement for the air separation unit of the Kemper IGCC, which resulted in a capital lease obligation at December 31, 2013 of approximately $83 million with an annual interest rate of 4.9%. Assets acquired under capital leases are recorded on the balance sheet as utility plant in service and the related obligations are classified as long-term debt.

At December 31, 2013 and 2012, the capitalized lease obligations for Georgia Power were $45 million and $50 million, respectively, with an interest rate of 7.9% for both years.

At December 31, 2013, Alabama Power had a capitalized lease obligation of $5 million for a natural gas pipeline with an annual interest rate of 6.9%.

At December 31, 2013 and 2012, a subsidiary of Southern Company had capital lease obligations of approximately $30 million in each period for certain computer equipment including desktops, laptops, servers, printers, and storage devices with interest rates that range from 1.4% to 3.2%.

Other Obligations

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

Assets Subject to Lien

Each of Southern Company's subsidiaries is organized as a legal entity, separate and apart from Southern Company and its other subsidiaries. Alabama Power and Gulf Power have granted one or more liens on certain of their respective property in connection with the issuance of certain series of pollution control revenue bonds with an outstanding principal amount of $194 million as of December 31, 2013. There are no agreements or other arrangements among the Southern Company system companies under which the assets of one company have been pledged or otherwise made available to satisfy obligations of Southern Company or any of its other subsidiaries.

In 2011, Mississippi Power purchased Plant Daniel Units 3 and 4 for approximately $85 million in cash and the assumption of $270 million face value (with a fair value on the assumption date of $346 million) of debt obligations of the lessor related to Plant Daniel Units 3 and 4, which mature in 2021 and bear interest at a fixed stated interest rate of 7.13% per annum. These obligations are secured by Plant Daniel Units 3 and 4 and certain personal property.

See "DOE Loan Guarantee Borrowings" for information regarding additional secured borrowings incurred by Georgia Power subsequent to December 31, 2013.

Bank Credit Arrangements

At December 31, 2013, committed credit arrangements with banks were as follows:

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

(a) No credit arrangements expire in 2017.

Most of the credit arrangements require payment of commitment fees based on the unused portion of the commitments or the maintenance of compensating balances with the banks. Commitment fees average less than 1/4 of 1% for Southern Company, the traditional operating companies, and Southern Power. Compensating balances are not legally restricted from withdrawal.

Southern Company and its subsidiaries expect to renew their credit arrangements as needed, prior to expiration.

Most of the credit arrangements with banks have covenants that limit debt levels to 65% of total capitalization, as defined in the agreements. For purposes of these definitions, debt excludes the long-term debt payable to affiliated trusts and, in certain arrangements, other hybrid securities and, for Mississippi Power, securitized debt relating to the securitization of certain costs of the Kemper IGCC. At December 31, 2013, Southern Company, the traditional operating companies, and Southern Power were each in compliance with their respective debt limit covenants.

A portion of the $5.2 billion unused credit arrangements with banks is allocated to provide liquidity support to the traditional operating companies' variable rate pollution control revenue bonds and commercial paper programs. The amount of variable rate

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pollution control revenue bonds requiring liquidity support as of December 31, 2013 was approximately $1.8 billion. In addition, at December 31, 2013, the traditional operating companies had $442 million of fixed rate pollution control revenue bonds that will be required to be remarketed within the next 12 months.

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

Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period[a]		
	Amount Outstanding	Weighted Average Interest Rate	
	(in millions)		
December 31, 2013:			
Commercial paper	$1,082	0.2	%
Short-term bank debt	400	0.9	%
Total	$1,482	0.4	%
December 31, 2012:			
Commercial paper	$820	0.3	%
Short-term bank debt	—	—	%
Total	$820	0.3	%

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

Redeemable Preferred Stock of Subsidiaries

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

There were no changes for the years ended December 31, 2013 and 2012 in redeemable preferred stock of subsidiaries for Southern Company.

7. COMMITMENTS

Fuel and Purchased Power Agreements

To supply a portion of the fuel requirements of the generating plants, the Southern Company system has entered into various long-term commitments for the procurement and delivery of fossil and nuclear fuel which are not recognized on the balance sheets. In 2013, 2012, and 2011, the traditional operating companies and Southern Power incurred fuel expense of $5.5 billion, $5.1 billion, and $6.3 billion, respectively, the majority of which was purchased under long-term commitments. Southern Company expects that a substantial amount of the Southern Company system's future fuel needs will continue to be purchased under long-term commitments. In addition, the Southern Company system has entered into various long-term commitments for the purchase of capacity and electricity, some of which are accounted for as operating leases or have been used by a third party to secure financing. Total capacity expense under PPAs accounted for as operating leases was $157 million, $171 million, and $199 million for 2013, 2012, and 2011, respectively.

Estimated total obligations under these commitments at December 31, 2013 were as follows:

	Capital Leases [4]	Operating Leases	Other
		(in millions)	
2014	$—	$201	$21
2015	20	244	13
2016	26	260	11
2017	27	263	8
2018	27	266	7
2019 and thereafter	541	2,104	58
Total	$641	$3,338	$118
Less: amounts representing executory costs [1]	142		
Net minimum lease payments	499		
Less: amounts representing interest [2]	166		
Present value of net minimum lease payments [3]	$333		

(1) Executory costs such as taxes, maintenance, and insurance (including the estimated profit thereon) are estimated and included in total minimum lease payments.

(2) Calculated Georgia Power's incremental borrowing rate at the inception of the leases.

(3) When the PPAs with non-affiliates begin in 2015, Georgia Power will recognize capital lease assets and capital lease obligations totaling $333 million, equal to the lesser of the present value of the net minimum lease payments or the estimated fair value of the leased property.

(4) A total of $1.3 billion of biomass PPAs included under the non-affiliate capital and operating leases is contingent upon the counterparty meeting specified contract dates for posting collateral and commercial operation.

Operating Leases

The Southern Company system has operating lease agreements with various terms and expiration dates. Total rent expense was $123 million, $155 million, and $176 million for 2013, 2012, and 2011, respectively. Southern Company includes any step rents, escalations, and lease concessions in its computation of minimum lease payments, which are recognized on a straight-line basis over the minimum lease term.

As of December 31, 2013, estimated minimum lease payments under operating leases were as follows:

	Minimum Lease Payments		
	Barges & Railcars	Other	Total
	(in millions)		
2014	$56	$45	$101
2015	35	40	75
2016	30	35	65
2017	12	32	44
2018	6	25	31
2019 and thereafter	15	120	135
Total	$154	$297	$451

For the traditional operating companies, a majority of the barge and railcar lease expenses are recoverable through fuel cost recovery provisions. In addition to the above rental commitments, Alabama Power and Georgia Power have obligations upon expiration of certain leases with respect to the residual value of the leased property. These leases have terms expiring through 2023 with maximum obligations under these leases of $59 million. At the termination of the leases, the lessee may either exercise its purchase option, or the property can be sold to a third party. Alabama Power and Georgia Power expect that the fair market value of the leased property would substantially reduce or eliminate the payments under the residual value obligations.

Guarantees

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

8. COMMON STOCK

Stock Issued

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

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

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

In 2012, Southern Company raised $397 million from the issuance of 12.1 million new common shares through the employee and director stock plans.

Stock Repurchased

In July 2012, Southern Company announced a program to repurchase shares to partially offset the incremental shares issued under its employee and director stock plans. There were no repurchases under this program in 2013 and no further repurchases under the program are anticipated.

Shares Reserved

At December 31, 2013, a total of 116 million shares were reserved for issuance pursuant to the Southern Investment Plan, the Employee Savings Plan, the Outside Directors Stock Plan, and the Omnibus Incentive Compensation Plan (which includes stock options and performance shares units as discussed below). Of the total 116 million shares reserved, there were 28 million shares of common stock remaining available for awards under the Omnibus Incentive Compensation Plan as of December 31, 2013.

Stock Options

Southern Company provides non-qualified stock options through its Omnibus Incentive Compensation Plan to a large segment of Southern Company system employees ranging from line management to executives. As of December 31, 2013, there were 5,776 current and former employees participating in the stock option program. The prices of options were at the fair market value of the shares on the dates of grant. These options become exercisable pro rata over a maximum period of three years from the date of grant. Southern Company generally recognizes stock option expense on a straight-line basis over the vesting period which equates to the requisite service period; however, for employees who are eligible for retirement, the total cost is expensed at the grant date. Options outstanding will expire no later than 10 years after the date of grant, unless terminated earlier by the Southern Company Board of Directors in accordance with the Omnibus Incentive Compensation Plan. Stock options held by employees of a company undergoing a change in control vest upon the change in control.

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

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

Year Ended December 31	2013	2012	2011
Expected volatility	16.6%	17.7%	17.5%
Expected term (in years)	5.0	5.0	5.0
Interest rate	0.9%	0.9%	2.3%
Dividend yield	4.4%	4.2%	4.8%
Weighted average grant-date fair value	$2.93	$3.39	$3.23

Southern Company's activity in the stock option program for 2013 is summarized below:

	Shares Subject to Option	Weighted Average Exercise Price
Outstanding at December 31, 2012	35,916,303	$36.37
Granted	9,152,716	44.17
Exercised	(6,078,735)	33.39
Cancelled	(170,918)	43.30
Outstanding at December 31, 2013	38,819,366	$38.64
Exercisable at December 31, 2013	24,150,442	$35.70

The number of stock options vested, and expected to vest in the future, as of December 31, 2013 was not significantly different from the number of stock options outstanding at December 31, 2013 as stated above. As of December 31, 2013, the weighted average remaining contractual term for the options outstanding and options exercisable was approximately six years and five years, respectively, and the aggregate intrinsic value for the options outstanding and options exercisable was $147 million and $142 million, respectively.

As of December 31, 2013, there was $9 million of total unrecognized compensation cost related to stock option awards not yet vested. That cost is expected to be recognized over a weighted-average period of approximately 11 months.

For the years ended December 31, 2013, 2012, and 2011, total compensation cost for stock option awards recognized in income was $25 million, $23 million, and $22 million, respectively, with the related tax benefit also recognized in income of $10 million, $9 million, and $8 million, respectively.

The total intrinsic value of options exercised during the years ended December 31, 2013, 2012, and 2011 was $77 million, $162 million, and $155 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $30 million, $62 million, and $60 million for the years ended December 31, 2013, 2012, and 2011, respectively.

Southern Company has a policy of issuing shares to satisfy share option exercises. Cash received from issuances related to option exercises under the share-based payment arrangements for the years ended December 31, 2013, 2012, and 2011 was $204 million, $397 million, and $528 million, respectively.

Performance Shares

Southern Company provides performance share award units through its Omnibus Incentive Compensation Plan to a large segment of Southern Company system employees ranging from line management to executives. The performance share units granted under the plan vest at the end of a three-year performance period which equates to the requisite service period. Employees that retire prior to the end of the three-year period receive a pro rata number of shares, issued at the end of the performance period, based on actual months of service prior to retirement. The value of the award units is based on Southern Company's total shareholder return (TSR) over the three-year performance period which measures Southern Company's relative performance against a group of industry peers. The performance shares are delivered in common stock following the end of the performance period based on Southern Company's actual TSR and may range from 0% to 200% of the original target performance share amount.

The fair value of performance share awards is determined as of the grant date using a Monte Carlo simulation model to estimate the TSR of Southern Company's stock among the industry peers over the performance period. Southern Company recognizes compensation expense on a straight-line basis over the three-year performance period without remeasurement. Compensation expense for awards where the service condition is met is recognized regardless of the actual number of shares issued. The expected volatility was based on the historical volatility of Southern Company's stock over a period equal to the performance period. The risk-free rate was based on the U.S. Treasury yield curve in effect at the time of grant that covers the performance period of the award units.

The following table shows the assumptions used in the pricing model and the weighted average grant-date fair value of performance share award units granted:

Year Ended December 31	2013	2012	2011
Expected volatility	12.0%	16.0%	19.2%
Expected term (in years)	3.0	3.0	3.0
Interest rate	0.4%	0.4%	1.4%
Annualized dividend rate	$1.96	$1.89	$1.82
Weighted average grant-date fair value	$40.50	$41.99	$35.97

Total unvested performance share units outstanding as of December 31, 2012 were 1,633,156. During 2013, 929,653 performance share units were granted, 807,702 performance share units were vested, and 111,348 performance share units were forfeited, resulting in 1,643,759 unvested units outstanding at December 31, 2013. In January 2014, the vested performance share award units were converted into 240,980 shares outstanding at a share price of $41.27 for the three-year performance and vesting period ended December 31, 2013.

For the years ended December 31, 2013, 2012, and 2011, total compensation cost for performance share units recognized in income was $31 million, $28 million, and $18 million, respectively, with the related tax benefit also recognized in income of $12 million, $11 million, and $7 million, respectively. As of December 31, 2013, there was $35 million of total unrecognized compensation cost related to performance share award units that will be recognized over a weighted-average period of approximately 11 months.

Diluted Earnings Per Share

For Southern Company, the only difference in computing basic and diluted earnings per share is attributable to awards outstanding under the stock option and performance share plans. The effect of both stock options and performance share award units were determined using the treasury stock method. Shares used to compute diluted earnings per share were as follows:

	Average Common Stock Shares		
	2013	2012	2011
	(in millions)		
As reported shares	877	871	857
Effect of options and performance share award units	4	8	7
Diluted shares	881	879	864

Stock options and performance share award units that were not included in the diluted earnings per share calculation because they were anti-dilutive were $16 million and were immaterial as of December 31, 2013 and 2012, respectively.

Common Stock Dividend Restrictions

The income of Southern Company is derived primarily from equity in earnings of its subsidiaries. At December 31, 2013, consolidated retained earnings included $6.1 billion of undistributed retained earnings of the subsidiaries.

9. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act (Act), Alabama Power and Georgia Power maintain agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at the companies' nuclear power plants. The Act provides funds up to $13.6 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $375 million by American Nuclear Insurers (ANI), with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. A company could be assessed up to $127 million per incident for each licensed reactor it operates but not more than an aggregate of $19 million per incident to be paid in a calendar year for each reactor. Such maximum assessment, excluding any applicable state premium taxes, for Alabama Power and Georgia Power, based on its ownership and buyback interests in all licensed reactors, is $255 million and $252 million, respectively, per incident, but not more than an aggregate of $38 million and $37 million, respectively, per company to be paid for each incident in any one year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due no later than September 10, 2018. See Note 4 to the financial statements herein for additional information on joint ownership agreements.

Alabama Power and Georgia Power are members of Nuclear Electric Insurance Limited (NEIL), a mutual insurer established to provide property damage insurance in an amount up to $500 million for members' operating nuclear generating facilities. Additionally, both companies have NEIL policies that currently provide decontamination, excess property insurance, and premature decommissioning coverage up to $2.25 billion for nuclear losses in excess of the $500 million primary coverage. These policies have a sublimit of $1.7 billion for non-nuclear losses.

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

A builders' risk property insurance policy has been purchased from NEIL for the construction of Plant Vogtle Units 3 and 4. This policy provides the Owners up to $2.75 billion for accidental property damage occurring during construction.

Under each of the NEIL policies, members are subject to assessments each year if losses exceed the accumulated funds available to the insurer. The current maximum annual assessments for Alabama Power and Georgia Power under the NEIL policies would be $43 million and $65 million, respectively.

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

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

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

10. FAIR VALUE MEASUREMENTS

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

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

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

As of December 31, 2013, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2013:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in millions)			
Assets:				
Energy-related derivatives	$—	$24	$—	$24
Interest rate derivatives	—	3	—	3
Nuclear decommissioning trusts:[(a)]				
Domestic equity	589	75	—	664
Foreign equity	35	196	—	231
U.S. Treasury and government agency securities	—	103	—	103
Municipal bonds	—	64	—	64
Corporate bonds	—	229	—	229
Mortgage and asset backed securities	—	132	—	132
Other investments	—	37	3	40
Cash equivalents	491	—	—	491
Other investments	9	—	4	13
Total	$1,124	$863	$7	$1,994
Liabilities:				
Energy-related derivatives	$—	$56	$—	$56

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

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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	$—	$26	$—	$26
Interest rate derivatives	—	10	—	10
Nuclear decommissioning trusts:[(a)]				
Domestic equity	453	65	—	518
Foreign equity	28	172	—	200
U.S. Treasury and government agency securities	—	134	—	134
Municipal bonds	—	55	—	55
Corporate bonds	—	234	—	234
Mortgage and asset backed securities	—	141	—	141
Other investments	—	20	—	20
Cash equivalents	384	—	—	384
Other investments	9	—	15	24
Total	$874	$857	$15	$1,746
Liabilities:				
Energy-related derivatives	$—	$111	$—	$111

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

Valuation Methodologies

The energy-related derivatives primarily consist of over-the-counter financial products for natural gas and physical power products including, from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, power prices, implied volatility, and Overnight Index Swap interest rates. Interest rate derivatives are also standard over-the-counter financial products valued using the market approach. Inputs for interest rate derivatives include LIBOR interest rates, interest rate futures contracts, and occasionally implied volatility of interest rate options. See Note 11 for additional information on how these derivatives are used.

For fair value measurements of investments within the nuclear decommissioning trusts, specifically the fixed income assets using significant other observable inputs and unobservable inputs, the primary valuation technique used is the market approach. External pricing vendors are designated for each of the asset classes in the nuclear decommissioning trusts with each security discriminately assigned a primary pricing source, based on similar characteristics.

A market price secured from the primary source vendor is then evaluated by management in its valuation of the assets within the trusts. As a general approach, market pricing vendors gather market data (including indices and market research reports) and integrate relative credit information, observed market movements, and sector news into proprietary pricing models, pricing systems, and mathematical tools. Dealer quotes and other market information including live trading levels and pricing analysts' judgment are also obtained when available.

"Other investments" include investments in funds that are valued using the market approach and income approach. Securities that are traded in the open market are valued at the closing price on their principal exchange as of the measurement date. Discounts are applied in accordance with GAAP when certain trading restrictions exist. For investments that are not traded in the open

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market, the price paid will have been determined based on market factors including comparable multiples and the expectations regarding cash flows and business plan execution. As the investments mature or if market conditions change materially, further analysis of the fair market value of the investment is performed. This analysis is typically based on a metric, such as multiple of earnings, revenues, earnings before interest and income taxes, or earnings adjusted for certain cash changes. These multiples are based on comparable multiples for publicly traded companies or other relevant prior transactions.
As of December 31, 2013 and 2012, the fair value measurements of investments calculated at net asset value per share (or its equivalent), as well as the nature and risks of those investments, were as follows:

	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
As of December 31, 2013:	(in millions)			
Nuclear decommissioning trusts:				
Foreign equity funds	$131	None	Monthly	5 days
Corporate bonds – commingled funds	8	None	Daily	Not applicable
Equity – commingled funds	65	None	Daily/Monthly	Daily/7 days
Other – commingled funds	24	None	Daily	Not applicable
Trust-owned life insurance	110	None	Daily	15 days
Cash equivalents:				
Money market funds	491	None	Daily	Not applicable
As of December 31, 2012:				
Nuclear decommissioning trusts:				
Foreign equity funds	$117	None	Monthly	5 days
Corporate bonds – commingled funds	9	None	Daily	Not applicable
Equity – commingled funds	55	None	Daily/Monthly	Daily/7 days
Other – commingled funds	10	None	Daily	Not applicable
Trust-owned life insurance	96	None	Daily	15 days
Cash equivalents:				
Money market funds	384	None	Daily	Not applicable

The NRC requires licensees of commissioned nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. Alabama Power and Georgia Power have the Funds to comply with the NRC's regulations. The foreign equity fund in Georgia Power's nuclear decommissioning trusts seeks to provide long-term capital appreciation. In pursuing this investment objective, the foreign equity fund primarily invests in a diversified portfolio of equity securities of foreign companies, including those in emerging markets. These equity securities may include, but are not limited to, common stocks, preferred stocks, real estate investment trusts, convertible securities and depositary receipts, including American depositary receipts, European depositary receipts and global depositary receipts, and rights and warrants to buy common stocks. Georgia Power may withdraw all or a portion of its investment on the last business day of each month subject to a minimum withdrawal of $1 million, provided that a minimum investment of $10 million remains. If notices of withdrawal exceed 20% of the aggregate value of the foreign equity fund, then the foreign equity fund's board may refuse to permit the withdrawal of all such investments and may scale down the amounts to be withdrawn pro rata and may further determine that any withdrawal that has been postponed will have priority on the subsequent withdrawal date.
The commingled funds in Georgia Power's nuclear decommissioning trusts are invested primarily in a diversified portfolio including, but not limited to, commercial paper, notes, repurchase agreements, and other evidences of indebtedness with a maturity not exceeding 13 months from the date of purchase. The commingled funds will, however, generally maintain a dollar-weighted average portfolio maturity of 90 days or less. The assets may be longer term investment grade fixed income obligations with maturity shortening provisions. The primary objective for the commingled funds is a high level of current income consistent with stability of principal and liquidity. The

commingled funds included within corporate bonds represent the investment of cash collateral received under the Funds' managers' securities lending program that can only be sold upon the return of the loaned securities. See Note 1 under "Nuclear Decommissioning" for additional information.

Alabama Power's nuclear decommissioning trust includes investments in TOLI. The taxable nuclear decommissioning trust invests in the TOLI in order to minimize the impact of taxes on the portfolio and can draw on the value of the TOLI through death proceeds, loans against the cash surrender value, and/or the cash surrender value, subject to legal restrictions. The amounts reported in the table above reflect the fair value of investments the insurer has made in relation to the TOLI agreements. The nuclear decommissioning trust does not own the underlying investments, but the fair value of the investments approximates the cash surrender value of the TOLI policies. The investments made by the insurer are in commingled funds. The commingled funds primarily include investments in domestic and international equity securities and predominantly high-quality fixed income securities. These fixed income securities may include U.S. Treasury and government agency fixed income securities, non-U.S. government and agency fixed income securities, domestic and foreign corporate fixed income securities, and, to some degree, mortgage and asset backed securities. The passively managed funds seek to replicate the performance of a related index. The actively managed funds seek to exceed the performance of a related index through security analysis and selection.

The money market funds are short-term investments of excess funds in various money market mutual funds, which are portfolios of short-term debt securities. The money market funds are regulated by the Securities and Exchange Commission and typically receive the highest rating from credit rating agencies. Regulatory and rating agency requirements for money market funds include minimum credit ratings and maximum maturities for individual securities and a maximum weighted average portfolio maturity. Redemptions are available on a same day basis up to the full amount of the Company's investment in the money market funds.

As of December 31, 2013 and 2012, other financial instruments for which the carrying amount did not equal fair value were as follows:

	Carrying Amount	Fair Value
	(in millions)	
Long-term debt:		
2013	$21,650	$22,197
2012	$21,530	$23,480

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

11. DERIVATIVES

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

Energy-Related Derivatives

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

To mitigate residual risks relative to movements in electricity prices, the traditional operating companies and Southern Power may enter into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market. To mitigate residual risks relative to movements in gas prices, the traditional operating companies and Southern Power may enter into fixed-price contracts for natural gas purchases; however, a significant portion of contracts are priced at market.

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

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

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

At December 31, 2013, the net volume of energy-related derivative contracts for natural gas positions totaled 275 million mmBtu (million British thermal units) for the Southern Company system, with the longest hedge date of 2018 over which the respective entity is hedging its exposure to the variability in future cash flows for forecasted transactions and the longest non-hedge date of 2017 for derivatives not designated as hedges.

In addition to the volumes discussed above, the traditional operating companies and Southern Power enter into physical natural gas supply contracts that provide the option to sell back excess gas due to operational constraints. The maximum expected volume of natural gas subject to such a feature is 9 million mmBtu.

For cash flow hedges, the amounts expected to be reclassified from accumulated OCI to revenue and fuel expense for the next 12-month period ending December 31, 2014 are immaterial for Southern Company.

Interest Rate Derivatives

Southern Company and certain subsidiaries may also enter into interest rate derivatives to hedge exposure to changes in interest rates. The derivatives employed as hedging instruments are structured to minimize ineffectiveness. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings, with any ineffectiveness recorded directly to earnings. Derivatives related to existing fixed rate securities are accounted for as fair value hedges, where the derivatives' fair value gains or losses and hedged items' fair value gains or losses are both recorded directly to earnings, providing an offset, with any difference representing ineffectiveness.

At December 31, 2013, the following interest rate derivatives were outstanding:

	Notional Amount	Interest Rate Received	Weighted Average Interest Rate Paid	Hedge Maturity Date	Fair Value Gain (Loss) December 31, 2013
	(in millions)				(in millions)
Fair value hedges of existing debt					
	$ 350	4.15%	3-month LIBOR + 1.96%	May 2014	$3

The estimated pre-tax losses that will be reclassified from accumulated OCI to interest expense for the next 12-month period ending December 31, 2014 are immaterial. The Company has deferred gains and losses that are expected to be amortized into earnings through 2037.

Foreign Currency Derivatives

Southern Company and certain subsidiaries may enter into foreign currency derivatives to hedge exposure to changes in foreign currency exchange rates arising from purchases of equipment denominated in a currency other than U.S. dollars. Derivatives related to a firm commitment in a foreign currency transaction are accounted for as a fair value hedge where the derivatives' fair value gains or losses and the hedged items' fair value gains or losses are both recorded directly to earnings. Derivatives related to a forecasted transaction are accounted for as a cash flow hedge where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings. Any ineffectiveness is recorded directly to earnings; however, Mississippi Power has regulatory approval allowing it to defer any ineffectiveness associated with firm commitments related to the Kemper IGCC to a regulatory asset. The derivatives employed as hedging instruments are structured to minimize ineffectiveness. At December 31, 2013, the fair value of the foreign currency derivative outstanding was immaterial.

Derivative Financial Statement Presentation and Amounts

At December 31, 2013 and 2012, the fair value of energy-related derivatives and interest rate derivatives was reflected in the balance sheets as follows:

Derivative Category	Asset Derivatives Balance Sheet Location	2013	2012	Liability Derivatives Balance Sheet Location	2013	2012
		(in millions)			(in millions)	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	$16	$10	Liabilities from risk management activities	$26	$74
	Other deferred charges and assets	7	13	Other deferred credits and liabilities	29	35
Total derivatives designated as hedging instruments for regulatory purposes		$23	$23		$55	$109
Derivatives designated as hedging instruments in cash flow and fair value hedges						
Interest rate derivatives:	Other current assets	$3	$7	Liabilities from risk management activities	$—	$—
	Other deferred charges and assets	—	3	Other deferred credits and liabilities	—	—
Total derivatives designated as hedging instruments in cash flow and fair value hedges		$3	$10		$—	$—
Derivatives not designated as hedging instruments						
Energy-related derivatives:	Other current assets	$—	$1	Liabilities from risk management activities	$1	$1
	Other deferred charges and assets	1	2	Other deferred credits and liabilities	—	1
Total derivatives not designated as hedging instruments		$1	$3		$1	$2
Total		$27	$36		$56	$111

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

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The Company's derivative contracts are not subject to master netting arrangements or similar agreements and are reported gross on the Company's financial statements. Some of these energy-related and interest rate derivative contracts contain certain provisions that permit intra-contract netting of derivative receivables and payables for routine billing and offsets related to events of default and settlements. Amounts related to energy-related derivative contracts at December 31, 2013 and 2012 are presented in the following tables. Interest rate derivatives presented in the tables above do not have amounts available for offset and are therefore excluded from the offsetting disclosure tables below.

Fair Value					
Assets	2013	2012	Liabilities	2013	2012
	(in millions)			(in millions)	
Energy-related derivatives presented in the Balance Sheet [(a)]	$24	$26	Energy-related derivatives presented in the Balance Sheet [(a)]	$56	$111
Gross amounts not offset in the Balance Sheet [(b)]	(22)	(23)	Gross amounts not offset in the Balance Sheet [(b)]	(22)	(23)
Net-energy related derivative assets	$2	$3	Net-energy related derivative liabilities	$34	$88

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

At December 31, 2013 and 2012, the pre-tax effects of unrealized derivative gains (losses) arising from energy-related derivative instruments designated as regulatory hedging instruments and deferred on the balance sheets were as follows:

Derivative Category	Unrealized Losses Balance Sheet Location	2013	2012	Unrealized Gains Balance Sheet Location	2013	2012
		(in millions)			(in millions)	
Energy-related derivatives:	Other regulatory assets, current	$(26)	$(74)	Other regulatory liabilities, current	$16	$10
	Other regulatory assets, deferred	(29)	(35)	Other regulatory liabilities, deferred	7	13
Total energy-related derivative gains (losses)		$(55)	$(109)		$23	$23

For the years ended December 31, 2013, 2012, and 2011, the pre-tax effects of interest rate and foreign currency derivatives designated as fair value hedging instruments on the statements of income were immaterial on a gross basis for Southern Company. Furthermore, the pre-tax effects of interest rate derivatives designated as fair value hedging instruments on Southern Company's statements of income were offset by changes to the carrying value of long-term debt and the pre-tax effects of foreign currency derivatives designated as fair value hedging instruments on Southern Company's statements of income were offset by changes in the fair value of the purchase commitment related to equipment purchases.

For the years ended December 31, 2013, 2012, and 2011, the pre-tax effects of energy-related derivatives and interest rate derivatives designated as cash flow hedging instruments recorded in OCI and reclassified into earnings were immaterial for Southern Company.

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

For the Southern Company system's energy-related derivatives not designated as hedging instruments, a portion of the pre-tax realized and unrealized gains and losses is associated with hedging fuel price risk of certain PPA customers and has no impact on net income or on fuel expense as presented in the Company's statements of income. As a result, the pre-tax effects of energy-related derivatives not designated as hedging instruments on the Company's statements of income were immaterial for any year presented. This third party hedging activity has been discontinued.

Contingent Features

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain Southern Company subsidiaries. At December 31, 2013, the fair value of derivative liabilities with contingent features was $9 million.

At December 31, 2013, Southern Company's collateral posted with its derivative counterparties was immaterial. The maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $9 million and include certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. If collateral is required, fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral are not offset against fair value amounts recognized for derivatives executed with the same counterparty.
Southern Company, the traditional operating companies, and Southern Power are exposed to losses related to financial instruments in the event of counterparties' nonperformance. Southern Company, the traditional operating companies, and Southern Power only enter into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P or with counterparties who have posted collateral to cover potential credit exposure. Southern Company, the traditional operating companies, and Southern Power have also established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate Southern Company's, the traditional operating companies', and Southern Power's exposure to counterparty credit risk. Therefore, Southern Company, the traditional operating companies, and Southern Power do not anticipate a material adverse effect on the financial statements as a result of counterparty nonperformance.

12. SEGMENT AND RELATED INFORMATION

The primary business of the Southern Company system is electricity sales by the traditional operating companies and Southern Power. The four traditional operating companies – Alabama Power, Georgia Power, Gulf Power and Mississippi Power – are vertically integrated utilities providing electric service in four Southeastern states. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market.
Southern Company's reportable business segments are the sale of electricity by the four traditional operating companies and Southern Power. Revenues from sales by Southern Power to the traditional operating companies were $346 million, $425 million, and $359 million in 2013, 2012, and 2011, respectively. The "All Other" column includes parent Southern Company, which does not allocate operating expenses to business segments. Also, this category includes segments below the quantitative threshold for separate disclosure. These segments include investments in telecommunications and leveraged lease projects. All other inter-segment revenues are not material. Financial data for business segments and products and services for the years ended December 31, 2013, 2012, and 2011 was as follows:

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	Electric Utilities Traditional Operating Companies (in millions)	Southern Power	Eliminations	Total	All Other	Eliminations	Consolidated
2013							
Operating revenues	$16,136	$1,275	$(376)	$17,035	$139	$(87)	$17,087
Depreciation and amortization	1,711	175	—	1,886	15	—	1,901
Interest income	17	1	—	18	2	(1)	19
Interest expense	714	74	—	788	36	—	824
Income taxes	889	46	—	935	(85)	(1)	849
Segment net income (loss)[(a)(b)]	1,486	166	—	1,652	(10)	2	1,644
Total assets	59,447	4,429	(101)	63,775	1,077	(306)	64,546
Gross property additions	5,226	633	—	5,859	9	—	5,868
2012							
Operating revenues	$15,730	$1,186	$(438)	$16,478	$141	$(82)	$16,537
Depreciation and amortization	1,629	143	—	1,772	15	—	1,787
Interest income	21	1	—	22	19	(1)	40
Interest expense	757	63	—	820	39	—	859
Income taxes	1,307	93	—	1,400	(66)	—	1,334
Segment net income (loss)[(a)]	2,145	175	1	2,321	33	(4)	2,350
Total assets	58,600	3,780	(129)	62,251	1,116	(218)	63,149
Gross property additions	4,813	241	—	5,054	5	—	5,059
2011							
Operating revenues	$16,763	$1,236	$(412)	$17,587	$149	$(79)	$17,657
Depreciation and amortization	1,576	124	—	1,700	16	1	1,717
Interest income	18	1	—	19	3	(1)	21
Interest expense	726	77	—	803	54	—	857
Income taxes	1,217	76	—	1,293	(74)	—	1,219
Segment net income (loss)[(a)]	2,052	162	—	2,214	(8)	(3)	2,203
Total assets	54,622	3,581	(127)	58,076	1,592	(401)	59,267
Gross property additions	4,589	255	—	4,844	9	—	4,853

(a) After dividends on preferred and preference stock of subsidiaries.
(b) Segment net income (loss) in 2013 includes $1.2 billion in pre-tax charges ($729 million after tax) for estimated probable losses on the Kemper IGCC.
See Note (3) under "Integrated Coal Gasification Combined Cycle – Kemper IGCC Construction Schedule and Cost Estimate" for additional information.

Products and Services

Electric Utilities' Revenues

Year	Retail (in millions)	Wholesale	Other	Total
2013	$14,541	$1,855	$639	$17,035
2012	14,187	1,675	616	16,478
2011	15,071	1,905	611	17,587

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13. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)
Summarized quarterly financial information for 2013 and 2012 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Consolidated Net Income After Dividends on Preferred and Preference Stock of Subsidiaries	Per Common Share Basic Earnings	Diluted Earnings	Dividends	Trading Price Range High	Low
	(in millions)							
March 2013	$3,897	$325	$81	$0.09	$0.09	$0.4900	$46.95	$42.82
June 2013	4,246	640	297	0.34	0.34	0.5075	48.74	42.32
September 2013	5,017	1,491	852	0.97	0.97	0.5075	45.75	40.63
December 2013	3,927	799	414	0.47	0.47	0.5075	42.94	40.03
March 2012	$3,604	$766	$368	$0.42	$0.42	$0.4725	$46.06	$43.71
June 2012	4,181	1,143	623	0.71	0.71	0.4900	48.45	44.22
September 2012	5,049	1,740	976	1.11	1.11	0.4900	48.59	44.64
December 2012	3,703	814	383	0.44	0.44	0.4900	47.09	41.75

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

SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA
For the Periods Ended December 2009 through 2013
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	2013	2012	2011	2010		2009
Operating Revenues (in millions)	$17,087	$16,537	$17,657	$17,456		$15,743
Total Assets (in millions)	$64,546	$63,149	$59,267	$55,032		$52,046
Gross Property Additions (in millions)	$5,868	$5,059	$4,853	$4,443		$4,913
Return on Average Common Equity (percent)	8.82	13.10	13.04	12.71		11.67
Cash Dividends Paid Per Share of Common Stock	$2.0125	$1.9425	$1.8725	$1.8025		$1.7325
Consolidated Net Income After Dividends on Preferred and Preference Stock of Subsidiaries (in millions)	$1,644	$2,350	$2,203	$1,975		$1,643
Earnings Per Share —						
Basic	$1.88	$2.70	$2.57	$2.37		$2.07
Diluted	1.87	2.67	2.55	2.36		2.06
Capitalization (in millions):						
Common stock equity	$19,008	$18,297	$17,578	$16,202		$14,878
Preferred and preference stock of subsidiaries	756	707	707	707		707
Redeemable preferred stock of subsidiaries	375	375	375	375		375
Long-term debt	21,344	19,274	18,647	18,154		18,131
Total (excluding amounts due within one year)	$41,483	$38,653	$37,307	$35,438		$34,091
Capitalization Ratios (percent):						
Common stock equity	45.8	47.3	47.1	45.7		43.6
Preferred and preference stock of subsidiaries	1.8	1.8	1.9	2.0		2.1
Redeemable preferred stock of subsidiaries	0.9	1.0	1.0	1.1		1.1
Long-term debt	51.5	49.9	50.0	51.2		53.2
Total (excluding amounts due within one year)	100.0	100.0	100.0	100.0		100.0
Other Common Stock Data:						
Book value per share	$21.43	$21.09	$20.32	$19.21		$18.15
Market price per share:						
High	$48.74	$48.59	$46.69	$38.62		$37.62
Low	40.03	41.75	35.73	30.85		26.48
Close (year-end)	41.11	42.81	46.29	38.23		33.32
Market-to-book ratio (year-end) (percent)	191.8	203.0	227.8	199.0		183.6
Price-earnings ratio (year-end) (times)	21.9	15.9	18.0	16.1		16.1
Dividends paid (in millions)	$1,762	$1,693	$1,601	$1,496		$1,369
Dividend yield (year-end) (percent)	4.9	4.5	4.0	4.7		5.2
Dividend payout ratio (percent)	107.1	72.0	72.7	75.7		83.3
Shares outstanding (in thousands):						
Average	876,755	871,388	856,898	832,189		794,795
Year-end	887,086	867,768	865,125	843,340		819,647
Stockholders of record (year-end)	143,800	149,628	155,198	160,426	*	92,799
Traditional Operating Company Customers (year-end) (in thousands):						
Residential	3,859	3,832	3,809	3,813		3,798
Commercial	583	580	579	580		580
Industrial	15	15	15	15		15

Other	10	9	9	9	9
Total	4,467	4,436	4,412	4,417	4,402
Employees (year-end)	26,300	26,439	26,377	25,940	26,112

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

SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA
For the Periods Ended December 2009 through 2013
Southern Company and Subsidiary Companies 2013 Annual Report

	2013	2012	2011	2010	2009
Operating Revenues (in millions):					
Residential	$6,011	$5,891	$6,268	$6,319	$5,481
Commercial	5,214	5,097	5,384	5,252	4,901
Industrial	3,188	3,071	3,287	3,097	2,806
Other	128	128	132	123	119
Total retail	14,541	14,187	15,071	14,791	13,307
Wholesale	1,855	1,675	1,905	1,994	1,802
Total revenues from sales of electricity	16,396	15,862	16,976	16,785	15,109
Other revenues	691	675	681	671	634
Total	$17,087	$16,537	$17,657	$17,456	$15,743
Kilowatt-Hour Sales (in millions):					
Residential	50,575	50,454	53,341	57,798	51,690
Commercial	52,551	53,007	53,855	55,492	53,526
Industrial	52,429	51,674	51,570	49,984	46,422
Other	902	919	936	943	953
Total retail	156,457	156,054	159,702	164,217	152,591
Wholesale sales	26,944	27,563	30,345	32,570	33,503
Total	183,401	183,617	190,047	196,787	186,094
Average Revenue Per Kilowatt-Hour (cents):					
Residential	11.89	11.68	11.75	10.93	10.60
Commercial	9.92	9.62	10.00	9.46	9.16
Industrial	6.08	5.94	6.37	6.20	6.04
Total retail	9.29	9.09	9.44	9.01	8.72
Wholesale	6.88	6.08	6.28	6.12	5.38
Total sales	8.94	8.64	8.93	8.53	8.12
Average Annual Kilowatt-Hour Use Per Residential Customer	13,144	13,187	13,997	15,176	13,607
Average Annual Revenue Per Residential Customer	$1,562	$1,540	$1,645	$1,659	$1,443
Plant Nameplate Capacity Ratings (year-end) (megawatts)	45,502	45,740	43,555	42,961	42,932
Maximum Peak-Hour Demand (megawatts):					
Winter	27,555	31,705	34,617	35,593	33,519
Summer	33,557	35,479	36,956	36,321	34,471
System Reserve Margin (at peak) (percent)	21.5	20.8	19.2	23.3	26.4
Annual Load Factor (percent)	63.2	59.5	59.0	62.2	60.6
Plant Availability (percent)*:					
Fossil-steam	87.7	89.4	88.1	91.4	91.3
Nuclear	91.5	94.2	93.0	92.1	90.1
Source of Energy Supply (percent):					
Coal	36.9	35.2	48.7	55.0	54.7
Nuclear	15.5	16.2	15.0	14.1	14.9
Hydro	3.9	1.7	2.1	2.5	3.9

Oil and gas	37.3	38.3	28.0	23.7	22.5
Purchased power	6.4	8.6	6.2	4.7	4.0
Total	100.0	100.0	100.0	100.0	100.0

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

MANAGEMENT COUNCIL

1. Thomas A. Fanning
Chairman, President, and Chief Executive Officer
Fanning, 57, joined the Company as a Financial Analyst in 1980. He has held his current position since December 2010. Previously, Fanning served as Executive Vice President and Chief Operating Officer of the Company, President and Chief Executive Officer of Gulf Power, and Chief Financial Officer of the Company, Georgia Power, and Mississippi Power.

2. Art P. Beattie
Executive Vice President and Chief Financial Officer
Beattie, 59, joined the Company in 1976 as a Junior Accountant with Alabama Power. He has held his current position since August 2010. Beattie is responsible for the Company's accounting, finance, tax, investor relations, treasury, and risk management functions. He also serves as Chief Risk Officer. Previously, Beattie served in several executive accounting and finance positions at Alabama Power, including Chief Financial Officer, Treasurer, and Comptroller.

3. W. Paul Bowers
Executive Vice President and President and Chief Executive Officer of Georgia Power
Bowers, 57, joined the Company as a Residential Sales Representative with Gulf Power in 1979. He has held his current position since January 2011. Previously, Bowers served as Chief Operating Officer of Georgia Power. He also served as Chief Financial Officer of the Company, President of Southern Company Generation, President and Chief Executive Officer of Southern Power, President and Chief Executive Officer of the Company's former United Kingdom subsidiary, and Senior Vice President and Chief Marketing Officer of the Company.

4. S. W. Connally, Jr.
President and Chief Executive Officer of Gulf Power
Connally, 44, joined the Company in 1989 as a Co-Op Student at Georgia Power. He has held his current position since July 2012. Previously, he served as Senior Vice President and Senior Production Officer for Georgia Power. He has served as Plant Manager at Plants Watson, Daniel, and Barry. He has also worked in Customer Operations and Sales and Marketing.

5. Mark A. Crosswhite
Executive Vice President and President and Chief Executive Officer of Alabama Power
Crosswhite, 51, joined the Company in 2004 as Senior Vice President and General Counsel for Southern Company Generation. He has held his current position since March 2014. He was previously Executive Vice President and Chief Operating Officer of the Company, President and Chief Executive Officer of Gulf Power, and Executive Vice President of External Affairs and Senior Vice President and General Counsel at Alabama Power. Prior to joining the Company, he was a Partner in the law firm of Balch & Bingham LLP in Birmingham, Alabama, where he practiced for 17 years.

6. Kimberly S. Greene
Executive Vice President and Chief Operating Officer
Greene, 47, has held her current position since March 2014. Previously, she was President and Chief Executive Officer of Southern Company Services, Inc. Prior to that, she was employed by Tennessee Valley Authority (TVA), where she served as Chief Financial Officer, Group President of Strategy and External Relations, and Chief Generation Officer. Prior to her time at TVA, she served as Senior Vice President of Finance and Treasurer for the Company and has held various positions with Mirant Corporation, including Chief Commercial Officer, South Region.

7. G. Edison Holland, Jr.
Executive Vice President and President and Chief Executive Officer of Mississippi Power
Holland, 61, joined the Company as Vice President and Corporate Counsel for Gulf Power in 1992. He was named to his current position in May 2013. Previously, he was Executive Vice President, General Counsel, and Corporate Secretary of the Company, President and Chief Executive Officer of Savannah Electric and Power Company, and Vice President of Power Generation and Transmission at Gulf Power.

8. James Y. Kerr II
Executive Vice President and General Counsel
Kerr, 50, assumed his current role in March 2014. Previously, he was a Partner with McGuireWoods LLP and a senior advisor at McGuireWoods Consulting LLC. He also served as co-chairman of McGuireWoods energy industry team with focus in the areas of energy transactions and finance, energy regulation, energy policy, and energy litigation. Prior to joining McGuireWoods, Kerr served as a Commissioner on the North Carolina Utilities Commission and was the former President of the National Association of Regulatory Utility Commissioners.

9. Stephen E. Kuczynski
Chairman, President, and Chief Executive Officer of Southern Nuclear
Kuczynski, 51, joined the Company in July 2011 as Chairman, President, and Chief Executive Officer of Southern Nuclear. Previously, he served as Senior Vice President of Engineering and Technical Services of Exelon Nuclear. He also served as Senior Vice President of Exelon Nuclear's Midwest operations, Senior Vice President of Operations Support, and Plant Manager and later Site Vice President for Exelon's Byron Nuclear Station.

10. Mark S. Lantrip
Executive Vice President and President and Chief Executive Officer, Southern Company Services, Inc.
Lantrip, 59, joined the Company in 1981 as an analyst in Gulf Power's Corporate Planning department. He assumed his current position in March 2014. Previously, Lantrip was Executive Vice President of Finance and Treasurer of Southern Company Services, Inc. and Treasurer of the Company, with responsibility for financial planning and analysis, enterprise risk management, trust finance, capital markets, and treasury.

11. Charles D. McCrary
Executive Vice President and Chairman of Alabama Power
McCrary, 62, joined the Company as an Assistant Project Planning Engineer with Alabama Power in 1973. He assumed his current position in March 2014. Previously, McCrary was President and Chief Executive Officer of Alabama Power, Chief Production Officer of the Company, and President and Chief Executive Officer of Southern Power. He has held executive positions at Alabama Power and Southern Nuclear.

12. Christopher C. Womack
Executive Vice President and President of External Affairs
Womack, 56, joined the Company in 1988 as a Governmental Affairs Representative for Alabama Power. He has held his current position since January 2009. Previously, Womack was Executive Vice President of External Affairs for Georgia Power. He has also served as Senior Vice President of Human Resources and Chief People Officer for the Company, as well as Senior Vice President and Senior Production Officer of Southern Company Generation.
Biographical information for the Board of Directors is set forth on pages 15 through 21 of the attached Proxy Statement.

STOCKHOLDER INFORMATION
Transfer Agent
Computershare Inc. (Computershare) is Southern Company's transfer agent, dividend-paying agent, investment plan administrator, and registrar. If you have questions concerning your registered shareowner account, please contact:
By Mail
Computershare
P.O. Box 30170
College Station, TX 77842-3170
By Courier
Computershare
211 Quality Circle
Suite 210
College Station, TX 77845
By Phone-United States
9 a.m. to 7 p.m. ET
Monday through Friday
800-554-7626
(Automated voice response system
24 hours/day, 7 days/week)
Hearing Impaired: 800-231-5469
By Phone-Outside United States
201-680-6693

Shareowner Services Internet Site
To take advantage of Computershare's online services, you will need to activate your account. This one-time authentication process will be used to validate your identity in addition to your 12-digit Investor ID and your Computershare Holder ID. The internet address is www.computershare.com/investor. Through this site, registered shareowners can securely access their account information, as well as submit numerous transactions. Also, transfer instructions and service request forms can be obtained.
Southern Investment Plan
The Southern Investment Plan provides a convenient way to purchase common stock and reinvest dividends. You can access the Southern Company internet site to review the prospectus.
Direct Registration
Southern Company common stock can be issued in direct registration (uncertificated) form. The stock is Direct Registration System eligible.
Dividend Payments
The entire amount of dividends paid in 2013 is taxable. The Board of Directors sets the record and payment dates for quarterly dividends. A dividend of 50.75 cents per share was paid in March 2014. For the remainder of 2014, projected record dates are May 5, August 4, and November 3. Projected payment dates for dividends declared during the remainder of 2014 are June 6, September 6, and December 6.
Auditors
Deloitte & Touche LLP
191 Peachtree St. NE
Suite 2000
Atlanta, GA 30303
During 2014, there were no changes in or disagreements with the auditors on accounting and financial disclosure.

Investor Information Line
For information about earnings and dividends, stock quotes, and current news releases, please visit www.investor.southerncompany.com.
Institutional Investor Inquiries
Southern Company maintains an investor relations office in Atlanta, 404-506-5310, to meet the information needs of institutional investors and securities analysts.
Electronic Delivery Of Proxy Materials
Any stockholder may enroll for electronic delivery of proxy materials at www.icsdelivery.com/so.
Environmental Information
Southern Company publishes a variety of information on its activities to meet the Company's environmental commitments. It is available online at www.southerncompany.com/planetpower/#reports.

To request printed materials, write to:
Larry Monroe
Chief Environmental Officer and Senior Vice President
Research and Environmental Affairs
600 North 18th St.
Bin 14N-8195
Birmingham, AL 35203-2206
Common Stock
Southern Company common stock is listed on the New York Stock Exchange under the ticker symbol SO. On December 31, 2013, Southern Company had 143,800 stockholders of record.

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