AVNET INC
Form 424B5
November 20, 2012
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Registration No. 333-184871

The information in this preliminary prospectus supplement is not complete and may be changed. This preliminary prospectus supplement and the accompanying prospectus are not an offer to sell these securities and are not soliciting an offer to buy these securities in any jurisdiction where the offer or sale is not permitted.

SUBJECT TO COMPLETION, DATED NOVEMBER 20, 2012

Preliminary Prospectus Supplement

November 20, 2012

(To Prospectus dated November 9, 2012)

$

Avnet, Inc.

% Notes due 2022

Avnet will pay interest on the notes on and of each year, commencing on , 2013. The notes will mature on , 2022, unless earlier redeemed.

Avnet may redeem some or all of the notes at any time at the make-whole redemption price set forth under Description of the Notes Optional Redemption in this prospectus supplement, plus accrued and unpaid interest, if any, to the redemption date. If Avnet experiences a change of control triggering event, Avnet may be required to purchase the notes from holders at a price equal to 101% of their principal amount plus accrued and unpaid interest to the repurchase date as described under Description of the Notes Change of Control in this prospectus supplement.

The notes will be Avnet s senior unsecured obligations and will rank equally with Avnet s other existing and future senior unsecured indebtedness.

See Risk Factors beginning on page S-7 of this prospectus supplement and in our Annual Report on Form 10-K for the fiscal year ended June 30, 2012, incorporated herein by reference, to read about risks you should consider before investing in the notes.

The notes will not be listed on any securities exchange. There is currently no market for the notes.

	Price to Public (1)	Underwriting Discount	Proceeds (Before Expenses) to Avnet
Per note	%	%	%
Total	$	$	$

(1) Plus accrued interest from , 2012, if settlement occurs after that date.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this prospectus supplement or the accompanying prospectus to which it relates is truthful or complete. Any representation to the contrary is a criminal offense.

The underwriters expect that delivery of the notes in book-entry form will be made through the facilities of The Depository Trust Company and its participants, including Euroclear Bank S.A./N.V., and Clearstream Banking, société anonyme, on or about , 2012.

Joint Book-Running Managers

BofA Merrill Lynch **RBS**

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PROSPECTUS SUPPLEMENT

PROSPECTUS

This document is in two parts. The first part is the prospectus supplement, which describes the specific terms of this offering and certain other matters relating to us and our financial condition. The second part is the prospectus, which gives more general information, some of which may not apply to this offering. You should read the entire prospectus supplement and the accompanying prospectus, including the documents incorporated by reference that are described under Where You Can Find More Information in this prospectus supplement.

You should rely only on the information contained or incorporated by reference in this prospectus supplement or the accompanying prospectus and any written communication from us specifying the final terms of the offering. Avnet has not, and the underwriters have not, authorized anyone to provide you with information that is different. To the extent the information in this prospectus supplement differs from the information contained in the prospectus, you should rely on information in this prospectus supplement. This prospectus supplement and the accompanying prospectus may only be used where it is legal to sell these securities. The information contained or incorporated by reference in this prospectus supplement or the accompanying prospectus and any written communication from us specifying the final terms of the offering, is only accurate as of the date of the applicable document.

References in this prospectus supplement and the accompanying prospectus to we, us, our, the Company and Avnet are to Avnet, Inc. and its consolidated subsidiaries, unless otherwise specified or unless the context otherwise requires.

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FORWARD-LOOKING STATEMENTS

This prospectus supplement and the accompanying prospectus contain or incorporate by reference forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended (the Securities Act), and Section 21E of the Securities Exchange Act of 1934, as amended (the Exchange Act), with respect to the financial condition, results of operations and business of Avnet. These statements are based on management s current expectations and are subject to uncertainties and changes in factual circumstances. Because forward-looking statements are subject to risks and uncertainties, actual results may differ materially from those expressed or implied by them. You can find many of these statements by looking for words like believes, plans, expects, anticipates, should, will, may, estimates or similar expressions in this supplement and the accompanying prospectus or in documents incorporated by reference in this prospectus supplement and the accompanying prospectus.

The forward-looking statements are subject to numerous assumptions, risks and uncertainties. You should not place undue reliance on forward-looking statements, each of which speaks only as of the date on which such statement is made. Avnet does not assume any obligation to update any forward-looking statement to reflect events or circumstances that occur after the date on which the statement is made. The following factors and the Risk Factors beginning on page S-7 of this prospectus supplement and in our Annual Report on Form 10-K for the fiscal year ended June 30, 2012, incorporated herein by reference, as well as other potential risks and uncertainties that are discussed in our reports and documents filed with the Securities and Exchange Commission (the SEC), could affect Avnet s future results, and could cause those results or other outcomes to differ materially from those expressed or implied in the forward-looking statements:

- the effect of global economic conditions, including the current global economic uncertainty;
- general economic and business conditions (domestic and foreign) affecting Avnet s financial performance and, indirectly, Avnet s credit ratings, debt covenant compliance, and liquidity and access to financing;
- competitive pressures among distributors of electronic components and computer products resulting in increased competition for existing customers or otherwise;
- adverse effects on our supply chain, shipping costs, customers and suppliers, including as a result of issues caused by natural and weather-related disasters;
- risks relating to our international sales and operations, including risks relating to the ability to repatriate funds, foreign currency fluctuations, duties and taxes and compliance with international and U.S. laws that apply to our international operations;
- cyclicality in the technology industry, particularly in the semiconductor sector;
- allocation of products by suppliers; and
- legislative or regulatory changes affecting Avnet s businesses.

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WHERE YOU CAN FIND MORE INFORMATION

This prospectus supplement and the accompanying prospectus are a part of a registration statement on Form S-3, which Avnet filed with the SEC under the Securities Act. Avnet refers you to this registration statement for further information concerning Avnet and this offering.

Avnet files annual, quarterly and special reports, proxy statements and other information with the SEC (File No. 1-4224). These filings contain important information which does not appear in this prospectus supplement or the accompanying prospectus. For further information about Avnet, you may obtain these filings over the Internet at the SEC s website at *http://www.sec.gov*. Avnet also posts certain of these filings on its web site at *www.avnet.com*. Information contained on our website is not intended to be incorporated by reference in this prospectus supplement or the accompanying prospectus and you should not consider that information a part of this prospectus supplement or the accompanying prospectus. Our website address is included in this prospectus supplement as an inactive textual reference only. You may also read and copy these filings at the SEC s Public Reference Room at 100 F Street, N.E., Room 1580, Washington, D.C. 20549. You may obtain information on the operation of the public reference room by calling the SEC at 800-732-0330.

INCORPORATION BY REFERENCE

The SEC allows Avnet to incorporate by reference information into this prospectus supplement and the accompanying prospectus, which means that Avnet can disclose important information to you by referring you to other documents which Avnet has filed or will file with the SEC. Avnet is incorporating by reference in this prospectus supplement and the accompanying prospectus (other than, in each case, documents or information deemed to have been furnished and not filed in accordance with SEC rules):

- Avnet s Annual Report on Form 10-K for the fiscal year ended June 30, 2012;
- Avnet s Quarterly Report on Form 10-Q for the quarter ended September 29, 2012; and
- a portion of Avnet s Current Report on Form 8-K filed on August 8, 2012 (Item 8.01 only) and Avnet s Current Reports on Form 8-K filed on August 10, 2012, August 24, 2012 and November 5, 2012.

All documents which Avnet files with the SEC pursuant to Section 13(a), 13(c), 14 or 15(d) of the Exchange Act (excluding information furnished pursuant to Item 2.02 or Item 7.01, or corresponding information furnished under Item 9.01 or included as an exhibit, on any current report on Form 8-K), after the date of this prospectus supplement and before the termination of this offering of securities will be deemed to be incorporated by reference in this prospectus supplement and the accompanying prospectus and to be a part of it from the filing date of such documents. Certain statements in or portions of a future document incorporated by reference in this prospectus supplement and the accompanying prospectus may update and replace statements in and portions of this prospectus supplement and the accompanying prospectus or the above listed documents. Nothing in this prospectus supplement and the accompanying prospectus will be deemed to incorporate information furnished but not filed with the SEC.

Avnet will provide you without charge, upon your written or oral request, a copy of the indenture relating to the notes offered hereby, and any of the documents incorporated by reference in this prospectus supplement and the accompanying prospectus, other than exhibits to such documents which are not specifically incorporated by reference into such documents. Please direct your written or telephone requests to the Corporate Secretary, Avnet, Inc., 2211 South 47th Street, Phoenix, Arizona 85034 (telephone (480) 643-2000).

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SUMMARY

The following summary contains information about Avnet and this offering. It does not contain all of the information that may be important to you in making a decision to purchase the notes. For a more comprehensive understanding of Avnet and this offering, Avnet urges you to read this entire prospectus supplement and the accompanying prospectus carefully, including the documents incorporated by reference herein, and Avnet s consolidated financial statements and related notes contained in such documents.

Avnet, Inc.

Avnet is one of the world s largest industrial distributors, based on sales, of electronic components, enterprise computer and storage products and embedded subsystems. Avnet creates a vital link in the technology supply chain that connects the world s leading electronic component and computer product manufacturers and software developers with a global customer base of original equipment manufacturers, or OEMs, electronic manufacturing services providers, original design manufacturers and value-added resellers, or VARs. Avnet distributes electronic components, computer products and software as received from its suppliers or with assembly or other value added by Avnet. Additionally, Avnet provides engineering design, materials management and logistics services, system integration and configuration, and supply chain services that can be customized to meet the requirements of both customers and suppliers.

Avnet has two primary operating groups Electronics Marketing and Technology Solutions. Both operating groups have operations in each of the three major economic regions of the world: the Americas; Europe, the Middle East and Africa; and Asia/Pacific, consisting of Asia, Australia and New Zealand. Each operating group has its own management team led by a group president and includes a regional president and senior executives within the operating group who manage the various functions within the businesses. Each operating group also has distinct financial reporting that is evaluated at the corporate level on which operating decisions and strategic planning for the company as a whole are made. Divisions exist within each operating group that serve primarily as sales and marketing units to further streamline the sales and marketing efforts within each operating group and enhance each operating group s ability to work with its customers and suppliers, generally along more specific product lines or geographies. However, each division relies heavily on the support services provided by the operating group as well as centralized support at the corporate level.

Electronics Marketing markets and sells semiconductors and interconnect, passive and electromechanical devices and embedded products for the world s leading electronic component manufacturers. Electronics Marketing markets and sells its products and services to a diverse customer base serving many end-markets, including automotive, communications, computer hardware and peripheral, industrial and manufacturing, medical equipment, military and aerospace. Electronics Marketing also offers an array of value-added services that help customers evaluate, design-in and procure electronic components throughout the lifecycle of their technology products and systems.

As a global IT solutions distributor, Technology Solutions collaborates with its customers and suppliers to create and deliver services, software and hardware solutions that address the business needs of end-user customers locally and around the world. Technology Solutions focuses on the global value-added distribution of enterprise computing servers and systems, software, storage, services and complex solutions from the world s foremost technology manufacturers, marketing and selling them to and through the VAR channel. Technology Solutions also serves the worldwide OEM market for computing technology, system integrators and non-PC OEMs that require embedded systems and solutions including engineering, product prototyping, integration and other value-added services. The operating group has sales and marketing divisions dedicated to these customer segments as well as independent software vendors.

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Avnet s common stock is quoted on the New York Stock Exchange under the symbol AVT.

Avnet s principal executive offices are located at 2211 South 47th Street, Phoenix, Arizona 85034. Avnet s main telephone number is (480) 643-2000.

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The Offering

The following summary contains basic information about the notes. It does not contain all the information that may be important to you. For a more complete understanding of the notes, see Description of the Notes in this prospectus supplement.

Issuer	Avnet, Inc., a New York corporation
Notes Offered	$ million in aggregate principal amount of % Notes due 2022.
Maturity	, 2022.
Interest	Interest on the notes will accrue from the date of their original issuance at the annual rate of % per year and will be payable in cash semi-annually in arrears on and of each year, commencing on , 2013.
Ranking	The notes will be Avnet s senior unsecured obligations and will rank equally in right of payment with all of Avnet s other existing and future senior unsecured indebtedness. At September 29, 2012, Avnet had approximately $1,388.1 million of unsecured senior indebtedness outstanding, including indebtedness incurred under Avnet s senior unsecured credit facility. The notes will not be guaranteed by any of Avnet s subsidiaries. The subsidiary debt to which the notes would be effectively subordinated totaled $249.4 million at September 29, 2012.
Optional Redemption	Avnet may, at its option, redeem some or all of the notes at any time, or from time to time, at the make-whole redemption price described under Description of the Notes Optional Redemption, plus accrued and unpaid interest, if any, to the redemption date.
Change of Control	If a Change of Control Triggering Event (as defined herein) occurs, each holder will have the right to require Avnet to repurchase all or any part ($2,000 or an integral multiple of $1,000 in excess thereof) of such holder s notes at a redemption price equal to 101% of the aggregate principal amount of notes repurchased plus accrued and unpaid interest, if any, on the notes repurchased, to the repurchase date. See Description of the Notes Change of Control.
Covenants	The indenture governing the notes contains covenants for the benefit of noteholders. These covenants restrict our ability to: incur certain secured debt; enter into sale and lease-back transactions; or

consolidate, merge or sell or transfer all or substantially all of our assets.

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	These covenants are, however, subject to significant exceptions. See Description of the Notes Covenants.
Further Issuances	We may create and issue additional notes ranking equally and ratably with the notes in all respects, so that such additional notes shall be consolidated with the notes, including for purposes of voting and redemptions.
Use of Proceeds	Avnet expects to use the net proceeds of this offering to repay amounts owed under Avnet s senior unsecured revolving credit facility and Avnet s accounts receivable securitization program. Certain affiliates of Merrill Lynch, Pierce, Fenner & Smith Incorporated and RBS Securities Inc. have commitments under Avnet s senior unsecured credit facility and certain affiliates of Merrill Lynch, Pierce, Fenner & Smith Incorporated have commitments under Avnet s accounts receivable securitization program. Consequently, certain affiliates of Merrill Lynch, Pierce, Fenner & Smith Incorporated and RBS Securities Inc. may receive more than 5% of the net proceeds of this offering. See Use of Proceeds in this prospectus supplement.
Form, Denomination and Registration	The notes will be issued in fully registered form in minimum denominations of $2,000 principal amount and multiples of $1,000 in excess thereof. The notes will be represented by one global note, deposited with the trustee under the indenture governing the notes as custodian for The Depository Trust Company (DTC) and registered in the name of Cede & Co., DTC s nominee. Beneficial interests in the global note will be shown on, and any transfers thereof will be effected only through records maintained by DTC and its participants. See Description of the Notes Depositary, Global Notes.
Governing Law	State of New York.
Listing	The notes will not be listed on any securities exchange.
Trustee	Wells Fargo Bank, National Association.

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Summary Financial Information and Other Data

The summary consolidated financial information and other data below is derived from the consolidated financial statements of Avnet. You should read those financial statements, accompanying notes and Management s Discussion and Analysis of Financial Condition and Results of Operations, all of which are incorporated by reference in this prospectus supplement and the accompanying prospectus from our Annual Report on Form 10-K for the fiscal year ended June 30, 2012 and our Quarterly Report on Form 10-Q for the quarter ended September 29, 2012. This summary financial information should be read in conjunction with the footnotes below as there are various special items recorded in certain periods presented.

	Three Months Ended		Fiscal Years Ended		
	September 29, 2012	October 1, 2011	June 30, 2012	July 2, 2011	July 3, 2010
	unaudited				
			(In millions)		
Statement of Operations Data:					
Sales	$ 5,870.1	$ 6,426.0	$ 25,707.5	$ 26,534.4	$ 19,160.2
Cost of sales	5,185.7	5,672.4	22,657.0	23,426.6	16,880.0
Gross profit	684.4	753.6	3,050.6	3,107.8	2,280.2
Selling, general and administrative expenses	547.0	530.5	2,092.8	2,100.7	1,619.2
Restructuring, integration and other charges (1)	37.4		73.6	77.2	25.4
Operating income	100.0	223.1	884.2	930.0	635.6
Other income (expense), net	1.5	(5.4)	(5.4)	10.7	2.5
Interest expense	(23.9)	(21.9)	(90.9)	(92.5)	(61.7)
Gain on bargain purchase and other (2)	31.3		2.9	22.7	
Gain on sale of assets (3)					8.8
Income before income taxes	108.9	195.8	790.8	871.0	585.1
Income tax provision	8.6	56.8	223.8	201.9	174.7
Net income	$ 100.3	$ 139.0	$ 567.0	$ 669.1	$ 410.4

	September 29, 2012	June 30, 2012	July 2, 2011
	unaudited		
		(In millions)	
Balance Sheet Data:			
Cash and cash equivalents	$ 1,043.0	$ 1,006.9	$ 675.3
Working capital (4)	3,573.4	3,455.7	3,749.5
Total assets	10,103.1	10,167.9	9,905.6
Total debt	2,348.4	2,144.4	1,516.6
Total liabilities	6,123.3	6,262.1	5,849.5
Shareholders equity	3,979.8	3,905.7	4,056.1

(1) During the first quarter of fiscal 2013, Avnet initiated expense reduction actions in both operating groups in response to continued weakness in business conditions. In addition, Avnet incurred acquisition and integration costs associated with recently acquired businesses. As a result, Avnet recorded restructuring, integration and other charges of $37.4 million pre-tax and $27.1 million after tax.

During fiscal 2012, Avnet took certain actions to reduce costs in both operating groups in response to market conditions and incurred acquisition and integration costs associated with recently acquired businesses. As a result, Avnet recorded restructuring, integration and other charges of $73.6 million pre-tax and $53.0 million after tax.

During fiscal 2011, Avnet incurred restructuring, integration and other charges totaling $77.2 million pre-tax and $56.2 million after tax related primarily to acquisition and integration activities associated with acquired businesses and also recorded credits related to prior restructuring reserves and acquisition adjustments.

During fiscal 2010, Avnet incurred restructuring, integration and other charges totaling $25.4 million pre-tax and $18.8 million after tax related to the remaining cost reduction actions announced in fiscal 2009, which were taken in response to market conditions, as well as integration costs associated with acquired businesses in addition to a value-added tax exposure and acquisition-related costs partially offset by a credit related to prior restructuring reserves.

(2) During the first quarter of fiscal 2013, Avnet acquired Internix, Inc., a company publicly traded on the Tokyo stock exchange, through a tender offer. After assessing the assets acquired and liabilities assumed, the consideration paid was below book value even though the price paid per share represented a premium to the trading levels at that time. Accordingly, Avnet recognized a gain on bargain purchase in the first quarter of fiscal 2013 of $31.3 million pre- and after tax.

During fiscal 2012, Avnet acquired Unidux Electronic Limited, a Singapore publicly traded company, through a tender offer for which the consideration paid was below book value. Accordingly, Avnet recognized a gain on bargain purchase of $4.3 million pre- and after tax. In addition, during fiscal 2012, Avnet recognized a loss of $1.4 million pre-tax and $0.9 million after tax related to a write-down of an investment in a small technology company and the write-off of certain deferred financing costs associated with the early termination of a credit facility.

During fiscal 2011, Avnet acquired Unidux, Inc., a Japanese publicly traded electronics distributor, through a tender offer for which the purchase price was below book value. As a result, Avnet recognized a gain on bargain purchase of $31.0 million pre- and after tax. Also during fiscal 2011, Avnet recognized a loss of $6.3 million pre-tax and $3.9 million after tax related to the write-down of prior investments in smaller technology start-up companies and recognized other charges of $2.0 million pre-tax and $1.4 million after tax primarily related to an impairment of buildings in Europe.

(3) During fiscal 2010, Avnet recognized a gain on sale of assets totaling $8.8 million pre-tax and $5.4 million after-tax as a result of certain earn-out provisions associated with the prior sale of an equity investment.

(4) Working capital is defined as current assets less current liabilities.

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RISK FACTORS

An investment in the notes involves risks. You should carefully consider the following risk factors relating to the offering of the notes, including the information under Risk Factors in our Annual Report on Form 10-K for the fiscal year ended June 30, 2012, before making an investment in the notes. You also should carefully consider any other discussion of risks or uncertainties contained or incorporated by reference in this prospectus supplement and the accompanying prospectus. The information contained or incorporated by reference in this prospectus supplement and the accompanying prospectus includes forward-looking statements that involve risks and uncertainties. See Forward-Looking Statements in this prospectus supplement. Avnet s actual results could differ materially from those anticipated in the forward-looking statements as a result of certain factors, including the risks described below and elsewhere in this prospectus supplement. Additional risks and uncertainties not currently known to Avnet or that Avnet currently believes are immaterial also may have a material adverse effect on its business, financial condition or results of operations, or could adversely affect the value of the notes offered by this prospectus supplement.

Any secured debt of Avnet will have claims with respect to the secured assets that are superior to that of the notes.

The indenture contains a covenant that restricts the incurrence of secured debt, although that restriction is subject to significant exceptions. Avnet s other debt instruments permit Avnet and its subsidiaries to incur a substantial amount of indebtedness that can be secured by Avnet s assets. Any secured debt issued by Avnet will be superior to the notes. In the event of a bankruptcy, liquidation, dissolution, reorganization or similar proceeding, Avnet s pledged assets would be available to satisfy obligations of the secured debt before any payment could be made on the notes. To the extent that these assets cannot satisfy in full Avnet s secured debt, the holders of such debt would have a claim for any shortfall that would rank equally in right of payment with the notes. In that event, Avnet may not have sufficient assets remaining to pay amounts due on any or all of the notes. At September 29, 2012, Avnet did not have any outstanding consolidated secured debt; however, it may issue secured debt in the future and such secured debt will have a right of payment superior to that of the notes.

Additionally, under Avnet s accounts receivable securitization program, Avnet is able to sell on an ongoing basis most of its domestic trade accounts receivables to a bankruptcy remote subsidiary, which, in turn, sells a portion of these receivables to a bank conduit. Receivables sold under the securitization program, and the proceeds from these receivables, will not be available for repayment of the notes and the indenture governing the notes does not restrict Avnet s ability to securitize its receivables. At September 29, 2012, Avnet had $711.0 million in borrowings outstanding under its securitization program.

The claims of creditors of Avnet s subsidiaries are superior to the claims of Avnet s equity interests in its subsidiaries.

Avnet s equity interest in its subsidiaries is subordinate to any debt and other liabilities and commitments, including trade payables and lease obligations, of Avnet s subsidiaries, whether or not secured. The notes will not be guaranteed by Avnet s subsidiaries and Avnet may not have direct access to the assets of its subsidiaries unless these assets are transferred by dividend or otherwise to Avnet. At September 29, 2012, Avnet s subsidiary debt to which the notes would effectively be subordinated totaled $249.4 million. Most of Avnet s subsidiary debt is guaranteed by Avnet. Avnet s subsidiaries also have the ability to borrow an additional $400.0 million under various lines of credit, which are cancelable on short-term notice. The ability of the subsidiaries to pay dividends or otherwise transfer assets to Avnet is subject to various restrictions under applicable law. Avnet s right to receive assets of any of its subsidiaries upon the subsidiary s liquidation or reorganization is subordinated effectively to the claim of that subsidiary s creditors. As noteholders claims to the assets of Avnet s subsidiaries are derivative of Avnet s equity claims in its subsidiaries, the claims of Avnet s subsidiaries creditors are superior to any claims of the noteholders to any assets of Avnet s subsidiaries and any subsidiaries that Avnet may in the future acquire or establish.

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An active trading market may not develop for the notes.

The notes are a new issue of securities with no established trading market. The notes will not be listed on any securities exchange. The underwriters have advised Avnet that they presently intend to make a market in the notes as permitted by applicable law. However, the underwriters are not obligated to make a market in the notes and may cease their market-making activities at any time at their discretion without notice. In addition, the liquidity of the trading market in the notes, and the market price quoted for the notes, may be adversely affected by changes in the overall market for securities and by changes in the financial performance or prospects of Avnet and/or companies in Avnet s industry generally. As a result, Avnet cannot assure you that an active trading market will develop or be maintained for the notes, in which case the market price and liquidity of the notes may be adversely affected.

The indenture does not restrict the amount of additional debt that Avnet may incur.

The notes and the indenture governing the notes do not limit the amount of unsecured debt that may be incurred by Avnet, permit Avnet to incur secured debt under specified circumstances, and permit Avnet s subsidiaries to incur debt, whether secured or unsecured, without restriction. The incurrence of additional debt by Avnet or any of its subsidiaries may have important consequences for noteholders, including making it more difficult for Avnet to satisfy its obligations with respect to the notes, a loss in the market value of the notes and a risk that the credit rating of the notes is lowered or withdrawn.

The indenture and the notes provide only limited protection against significant corporate events that could adversely affect noteholders investments in the notes.

Although the indenture and the notes contain terms intended to provide protection to holders of notes upon the occurrence of certain events involving significant corporate transactions and Avnet s creditworthiness, these terms are limited and may not be sufficient to protect such holders investment in the notes. As described under Description of the Notes Change of Control, upon the occurrence of a Change of Control Triggering Event (as defined herein), each holder of notes will have the right to require Avnet to repurchase all or any part of such holder s notes at a price equal to 101% of their principal amount, plus accrued and unpaid interest, if any, to the repurchase date. However, the definition of the term Change of Control Triggering Event is limited and does not cover a variety of transactions (such as acquisitions by Avnet, recapitalizations or asset sales not constituting the disposition of all or substantially all of Avnet s assets) that could negatively affect the value of the notes. As a result, holders of notes should be aware that the terms of the indenture and the notes do not restrict Avnet s ability to engage in, or to otherwise be a party to, various corporate transactions, circumstances and events that could adversely affect such holders investment in the notes.

Avnet may be unable to purchase the notes upon a change of control.

Upon the occurrence of a Change of Control Triggering Event, each holder of notes will have the right to require Avnet to repurchase all or any part of such holder s notes at a price equal to 101% of their principal amount, plus accrued and unpaid interest, if any, to the repurchase date. If Avnet experiences a Change of Control Triggering Event, there can be no assurance that Avnet would have sufficient financial resources available to satisfy its obligations to repurchase the notes. Avnet s failure to repurchase the notes as required under the indenture governing the notes would result in a default under the indenture, which could have material adverse consequences for Avnet and the holders of the notes. See Description of the Notes Change of Control.

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Noteholders may not be able to determine when a change of control has occurred giving rise to such holders rights to having their notes repurchased by Avnet following a sale of all or substantially all of Avnet s assets.

The Change of Control definition applicable to the notes as described under Description of the Notes Change of Control includes a clause relating to the sale, conveyance, transfer or lease of all or substantially all of Avnet s assets and the assets of Avnet s subsidiaries taken as a whole. Although there is a limited body of case law interpreting the term substantially all, there is no precise established definition of the phrase under applicable law. Accordingly, a noteholder s ability to require Avnet to repurchase such holder s notes as a result of a sale, lease, transfer, conveyance or other disposition of less than all or substantially all of the assets of Avnet and its subsidiaries, taken as a whole, to another person may be uncertain in some circumstances.

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RATIO OF EARNINGS TO FIXED CHARGES

The following table sets forth our ratio of earnings to fixed charges for the periods presented.

Three Months Ended		Fiscal Year Ended				
September 29, 2012 (1)	October 1, 2011	June 30, 2012 (2)	July 2, 2011 (3)	July 3, 2010 (4)	June 27, 2009 (5)	June 28, 2008 (6)
4.4x	7.5x	7.4x	8.0x	7.8x	*	7.2x

* Earnings were deficient in covering fixed charges by $1.09 billion for the fiscal year ended June 27, 2009.

(1) Includes the impact of restructuring, integration and other charges of $37.4 million pre-tax and a gain on bargain purchase of $31.3 million pre-tax.

(2) Includes the impact of restructuring, integration and other charges of $73.6 million pre-tax.

(3) Includes the impact of restructuring, integration and other charges of $77.2 million pre-tax.

(4) Includes the impact of restructuring, integration and other charges of $25.4 million pre-tax and a gain on sale of assets totaling $8.8 million pre-tax as a result of certain earn-out provisions associated with the prior sale of an equity investment.

(5) Includes the impact of non-cash goodwill and intangible asset impairment charges totaling $1.41 billion pre-tax, restructuring, integration and other charges totaling $99.3 million pre-tax and a gain on sale of assets totaling $14.3 million pre-tax.

(6) Includes the impact of restructuring, integration and other charges totaling $38.9 million pre-tax and a gain on sale of assets totaling $49.9 million pre-tax.

USE OF PROCEEDS

The net proceeds from this offering will be approximately $ million, after deducting the underwriting discount but before deducting other transaction expenses payable by Avnet. Avnet expects to use the net proceeds from this offering to repay amounts owed under Avnet s senior unsecured revolving credit facility and Avnet s accounts receivable securitization program. There were $240.0 million of borrowings under the credit facility, with an interest rate of 1.51%, as of September 29, 2012, and $711.0 million of borrowings under the securitization program, with an interest rate of 0.60%, as of September 29, 2012. The credit facility has a five-year term that expires in November 2016, and the securitization program has a one-year term that expires in August 2013.

Certain affiliates of Merrill Lynch, Pierce, Fenner & Smith Incorporated and RBS Securities Inc. have commitments under Avnet s senior unsecured credit facility and certain affiliates of Merrill Lynch, Pierce, Fenner & Smith Incorporated have commitments under Avnet s accounts receivable securitization program. Consequently, certain affiliates of Merrill Lynch, Pierce, Fenner & Smith Incorporated and RBS Securities Inc. may receive more than 5% of the net proceeds of this offering (see Underwriting Conflicts of Interest).

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CAPITALIZATION

The following table sets forth our capitalization as of September 29, 2012 on:

- an historical basis; and
- an as adjusted basis to give effect to this offering (but not the application of the net proceeds of this offering).

The actual information in the table is derived from, and you should read the information below in conjunction with, Avnet s historical financial statements and the accompanying notes thereto incorporated by reference in this prospectus supplement. The tables should also be read together with Management s Discussion and Analysis of Financial Condition and Results of Operations included in Avnet s Annual Report on Form 10-K for the fiscal year ended June 30, 2012 and its Quarterly Report on Form 10-Q for the quarter ended September 29, 2012 incorporated by reference herein.

	As of September 29, 2012	
	Historical	As Adjusted
	(Unaudited)	
	(In thousands)	
Cash and cash equivalents	$ 1,043,033	$
Short-term debt	$ 948,596	$
Long-term debt	1,399,832	
% Notes due		
Total debt	2,348,428	
Shareholders equity	3,979,783	
Total capitalization (1)	$ 6,328,211	$

(1) Total capitalization consists of short-term debt, long-term debt and shareholders equity.

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DESCRIPTION OF THE NOTES

The notes will be issued as a series of debt securities under an indenture dated as of June 22, 2010, between us and Wells Fargo Bank, National Association, as trustee. The following description of notes is a summary of material provisions of the notes and the indenture, but does not include all the provisions of the notes and the indenture. We urge you to read the indenture because it fully defines the rights of holders of the notes. You may obtain a copy of the indenture without charge. See Incorporation by Reference in this prospectus supplement. Capitalized terms used but not otherwise defined in this section have the meanings assigned to them in the indenture.

The terms of the notes include those set forth in the notes, those stated in the indenture and those made part of the indenture by reference to the Trust Indenture Act of 1939, as amended. The notes are subject to all such terms, and investors are referred to the indenture and the Trust Indenture Act of 1939, as amended, for a statement thereof.

When we refer to Avnet, Avnet, Inc., us, we, or our in this Description of the Notes section of this prospectus supplement, we refer only t Avnet, Inc., a New York corporation, and not its subsidiaries.

General

The notes will be initially limited to $ million aggregate principal amount. We may create and issue additional notes of the series of notes offered hereby from time to time without the consent of the then holders of the notes. Any additional notes will be consolidated with, and treated as part of the same series of notes as, the initial notes for all purposes under the indenture, including voting and redemptions.

The notes will mature on , 2022.

The notes will be issued in registered form only in denominations of $2,000 and integral multiples of $1,000 in excess thereof.

The notes will be our senior unsecured obligations and will rank equally with our other existing and future senior unsecured indebtedness, including the indebtedness incurred under Avnet s credit facility, which amounted to approximately $1,388.1 million at September 29, 2012. The notes will not be guaranteed by any of our subsidiaries and so will be effectively subordinated to the debt of these subsidiaries with respect to Avnet s equity interests in the assets of these subsidiaries. The subsidiary debt to which the notes would effectively be subordinated totaled $249.4 million at September 29, 2012. Substantially all of the debt of our subsidiaries has been incurred by foreign subsidiaries, primarily to fund their working capital requirements.

The notes will not have the benefit of any sinking fund.

Interest

The notes will bear interest from , 2012 at the annual rate set forth on the cover page of this prospectus supplement. Interest will be payable semi-annually on and of each year, beginning on , 2013, to the persons in whose names the notes are registered in the security register at the close of business on and prior to the relevant interest payment date. Interest on the notes will be computed on the basis of a 360-day year of twelve 30-day months.

Payment, Exchange and Transfer

Payment of principal of, and premium, if any, and interest on, the notes will be payable, and the exchange of and the transfer of notes will be registrable, at the office of the trustee or at any other office or agency maintained by us for that purpose subject to the limitations of the indenture. We will not require a service charge for any registration of transfer or exchange of the notes, but may require payment of a sum sufficient to cover any tax or other governmental charge.

Optional Redemption

We may redeem the notes, in whole or in part, at our option, at any time and from time to time prior to maturity on at least 30 days , but not more than 60 days , prior notice mailed to the registered address of each holder of the notes. The redemption price will be equal to the greater of:

100% of the principal amount of the notes to be redeemed; and

the sum of the present values of the Remaining Scheduled Payments (as defined below) discounted, on a semiannual basis (assuming a 360-day year consisting of twelve 30-day months) at a rate equal to the sum of the Treasury Rate (as defined below) plus basis points;

plus, in each case, accrued and unpaid interest, if any, on the notes to the redemption date. The principal amount of a note remaining outstanding after redemption in part must be $2,000 or an integral multiple of $1,000 in excess thereof.

For purposes of the optional redemption provision of the notes, the following definitions will be applicable:

Comparable Treasury Issue means the United States Treasury security or securities selected by an Independent Investment Banker as having an actual or interpolated maturity comparable to the remaining term of the notes to be redeemed that would be utilized, at the time of selection and in accordance with customary financial practice, in pricing new issues of corporate debt securities of a comparable maturity to the remaining term of such notes.

Comparable Treasury Price means, with respect to any redemption date, (1) the average of the Reference Treasury Dealer Quotations for such redemption date after excluding the highest and lowest of such Reference Treasury Dealer Quotations, or (2) if we obtain fewer than four such Reference Treasury Dealer Quotations, the average of all such quotations.

Independent Investment Banker means one of the Reference Treasury Dealers appointed by us.

Reference Treasury Dealer means Merrill Lynch, Pierce, Fenner & Smith Incorporated and RBS Securities Inc. (or their respective affiliates that are primary U.S. Government securities dealers in New York City (each, a Primary Treasury Dealer)) and their respective successors and two other Primary Treasury Dealers as may be selected from time to time by us. If any of the foregoing ceases to be a Primary Treasury Dealer, we will substitute therefor another Primary Treasury Dealer.

Reference Treasury Dealer Quotations means, with respect to each Reference Treasury Dealer and any redemption date, the average, as determined by us, of the bid and ask prices for the Comparable Treasury Issue (expressed in each case as a percentage of its principal amount) quoted in writing to us by such Reference Treasury Dealer at 3:30 p.m. (New York City time) on the third business day preceding such redemption date.

Remaining Scheduled Payments means, with respect to each note to be redeemed, the remaining scheduled payments of principal of and interest on the note that would be due after the related redemption date but for the redemption. If that redemption date is not an interest payment date with respect to a note, the amount of the next succeeding scheduled interest payment on the note will be reduced by the amount of interest accrued on the note to the redemption date.

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Treasury Rate means, with respect to any redemption date, the rate per annum equal to the semiannual equivalent yield to maturity or interpolation (on a day count basis) of the interpolated Comparable Treasury Issue, assuming a price for the Comparable Treasury Issue (expressed as a percentage of its principal amount) equal to the Comparable Treasury Price for such redemption date.

In the event that we choose to redeem less than all of the notes, selection of the notes for redemption will be made by the trustee on a *pro rata* basis, by lot or by such method as the trustee deems fair and appropriate, in accordance with DTC s applicable procedures.

The notice of redemption that relates to any note that is redeemed in part only will state the portion of the principal amount thereof to be redeemed. A new note in principal amount equal to the unredeemed portion thereof will be issued in the name of the holder thereof upon cancellation of the original note. On and after the redemption date, interest will cease to accrue on notes or portions thereof called for redemption so long as we have deposited with the paying agent funds in satisfaction of the redemption price.

Change of Control

If a Change of Control Triggering Event occurs, unless we have exercised our right to redeem the notes as described under Optional Redemption, noteholders will have the right to require us to repurchase all or any part of their notes pursuant to the offer described below (the Change of Control Offer) on the terms set forth in the notes. In a Change of Control Offer, we will offer payment in cash equal to 101% of the aggregate principal amount of notes repurchased plus accrued and unpaid interest, if any, on the notes repurchased, to the repurchase date (the Change of Control Payment) (subject to the right of holders of record on the relevant record date to receive interest due on the interest payment date). The principal amount of a note remaining outstanding after a repurchase in part must be $2,000 or an integral multiple of $1,000 in excess thereof.

Within 30 days following the date upon which the Change of Control Triggering Event has occurred or, at our option, prior to any Change of Control, but after the public announcement of the transaction that may or will constitute a Change of Control, except to the extent that we have exercised our right to redeem the notes as described above, we will cause a notice to be mailed to you with a copy to the trustee describing the transaction or transactions that may or will constitute a Change of Control Triggering Event and offering to repurchase the notes on the date specified in the notice, which date will be no earlier than 30 days, but no later than 60 days from the date such notice is mailed (the Change of Control Payment Date). The notice will, if mailed prior to the date of consummation of the Change of Control, state that the Change of Control Offer is conditioned on the Change of Control being consummated on or prior to the Change of Control Payment Date.

On the Change of Control Payment Date, we will, to the extent lawful:

- accept for payment all notes or portions of notes properly tendered pursuant to the Change of Control Offer;

- deposit with the paying agent an amount equal to the Change of Control Payment in respect of all notes or portions of notes properly tendered pursuant to the applicable Change of Control Offer; and

- deliver or cause to be delivered to the trustee the notes properly accepted together with an officers certificate stating the aggregate principal amount of notes or portions of notes being purchased by us.

We will comply with the requirements of Rule 14e-1 under the Exchange Act and any other securities laws and regulations thereunder to the extent those laws and regulations are applicable in connection with the repurchase of the notes as a result of a Change of Control Triggering Event. To the extent that the provisions of any securities laws or regulations conflict with the Change of Control provisions of the notes, we will comply with the applicable securities laws and regulations and will not be deemed to have breached our obligations under the Change of Control provisions of the notes by virtue of such conflicts.

We will not be required to make a Change of Control Offer upon a Change of Control Triggering Event if a third party makes such an offer in the manner, at the times and otherwise in compliance with the requirements for an offer made by us, and such third party purchases all notes properly tendered and not withdrawn under its offer. In the event that such third party terminates or defaults on its offer, we will be required to make a Change of Control Offer treating the date of such termination or default as though it were the date of the Change of Control Triggering Event.

For purposes of the Change of Control Offer provisions of the notes, the following definitions will be applicable:

Below Investment Grade Rating Event means the rating on the notes is lowered by each of the Rating Agencies and the notes are rated below an Investment Grade Rating by each of the Rating Agencies on any day during the period (the Trigger Period) commencing on the date 60 days prior to the first public announcement by us of any Change of Control or pending Change of Control and ending 60 days following the consummation of such Change of Control (which Trigger Period will be extended so long as the rating of the notes is under publicly announced consideration for possible downgrade by any of the Rating Agencies).

Change of Control means the occurrence of any of the following:

(1) the direct or indirect sale, transfer, conveyance or other disposition (other than by way of merger or consolidation), in one or a series of related transactions, of all or substantially all of our properties or assets and of our subsidiaries properties or assets taken as a whole to any person (as that term is used in Section 13(d)(3) of the Exchange Act) other than to us or one of our subsidiaries;

(2) the adoption of a plan relating to our liquidation or dissolution;

(3) the consummation of any transaction (including, without limitation, any merger or consolidation) the result of which is that any person (as defined above) becomes the beneficial owner (as defined in Rule 13d-3 and 13d-5 under the Exchange Act), directly or indirectly, of more than 50% of the then outstanding number of shares of our Voting Stock measured by voting power rather than number of shares;

(4) we consolidate with, or merge with or into any person, or any person consolidates with, or merges with or into, us, in any such event pursuant to a transaction in which any of our outstanding Voting Stock or the outstanding Voting Stock of such other person is converted into or exchanged for cash, securities or other property, other than any such transaction where the shares of our Voting Stock outstanding immediately prior to such transaction constitute, or are converted into or exchanged for, a majority of the Voting Stock (measured by voting power rather than number of shares) of the surviving person immediately after giving effect to such transaction; or

(5) the first day on which a majority of the members of our board of directors are not Continuing Directors.

Change of Control Triggering Event means the occurrence of both a Change of Control and a Below Investment Grade Rating Event.

Continuing Directors means, as of any date of determination, any member of our board of directors who (1) was a member of the board of directors on the original issuance date of the notes or (2) was nominated for election, elected or appointed to such board of directors with the approval of a majority of the Continuing

Directors who were members of such board of directors at the time of such nomination, election or appointment (either by a specific vote or by approval of the Company s proxy statement in which such member was named as a nominee for election as a director, without objection to such nomination).

Investment Grade Rating means a rating equal to or higher than Baa3 (or the equivalent) by Moody s and BBB- (or the equivalent) by S&P, and the equivalent rating from any replacement Rating Agency or Rating Agencies.

Moody s means Moody s Investors Service, Inc. and any of its successors.

Rating Agencies means (1) each of Moody s and S&P; and (2) if either Moody s or S&P ceases to rate the notes or fails to make a rating of the notes publicly available for reasons outside of our control, a nationally recognized statistical rating organization within the meaning of Section 3(a)(62) of the Exchange Act, selected by us (as certified by a resolution of our board of directors) as a replacement rating agency for Moody s or S&P, or both of them, as the case may be.

S&P means Standard & Poor s Ratings Services, a division of The McGraw-Hill Companies, Inc., and any of its successors.

The Change of Control definition includes a clause relating to the sale, lease transfer, conveyance or other disposition of all or substantially all of our assets and the assets of our subsidiaries taken as a whole. Although there is a limited body of case law interpreting the term substantially all, there is no precise established definition of this phrase under applicable law. Accordingly, the ability of a holder of notes to require us to repurchase its notes as a result of a sale, lease, transfer, conveyance or other disposition of less than all of our assets and the assets of our subsidiaries taken as a whole to another person may be uncertain in some circumstances.

Covenants

The notes will provide that we will be subject to the following covenants for the benefit of the notes.

Restriction on Secured Debt

Avnet covenants in the notes, for the benefit of the noteholders, that if Avnet or any Restricted Subsidiary after the original issuance date of the notes incurs or guarantees any loans, notes, bonds, debentures or other similar evidences of indebtedness for money borrowed (Certain Debt) secured by a mortgage, pledge or lien (Mortgage) on any Principal Property of Avnet or any Restricted Subsidiary, or on any share of capital stock or Certain Debt of a Restricted Subsidiary, Avnet will secure or cause such Restricted Subsidiary to secure the notes equally and ratably with (or, at Avnet s option, before) such secured Certain Debt, unless the aggregate principal amount of all such secured Certain Debt (plus the amount of all Attributable Debt which is not excluded as described below under Restriction on Sale and Leaseback Transactions) would not exceed 10% of Consolidated Net Assets.

This restriction will not apply to, and there will be excluded from secured Certain Debt in any computation of the above restriction, Certain Debt secured by:

(a) Mortgages on property (including any shares of capital stock or Certain Debt) of any Person existing at the time such Person becomes a Restricted Subsidiary;

(b) Mortgages in favor of Avnet or a Restricted Subsidiary;

(c) Mortgages in favor of governmental bodies to secure progress, advance or other payments;

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(d) Mortgages on property, shares of capital stock or Certain Debt existing at the time of acquisition thereof (including acquisition through merger or consolidation) and purchase money and construction or improvement Mortgages which are entered into within 180 days after the acquisition of such property, shares or Certain Debt or, in the case of real property, within 180 days after the later of:

- the completion of construction on, substantial repair to, alteration or development of, or substantial improvement to, such property; and
- the commencement of commercial operations on such property;

(e) mechanics and similar liens arising in the ordinary course of business in respect of obligations not due or being contested in good faith;

(f) Mortgages arising from deposits with, or the giving of any form of security to, any governmental agency required as a condition to the transaction of business or to the exercise of any privilege, franchise or license;

(g) Mortgages for taxes, assessments or government charges or levies which are not then due or, if delinquent, are being contested in good faith;

(h) Mortgages (including judgment liens) arising from legal proceedings being contested in good faith;

(i) Mortgages existing at the original issuance date of the notes; and

(j) any extension, renewal or refunding of any Mortgage referred to in the clauses (a) through (i) above.

Restriction on Sale and Leaseback Transactions

Avnet covenants in the notes, for the benefit of the noteholders, that Avnet will not itself, and will not permit any Restricted Subsidiary to, enter into any sale and leaseback transaction involving any Principal Property, unless after giving effect thereto the aggregate amount of all Attributable Debt with respect to all such transactions (plus the aggregate principal amount of all secured Certain Debt which is not excluded as described above under Restriction on Secured Debt) would not exceed 10% of Consolidated Net Assets.

This restriction will not apply to, and there will be excluded from Attributable Debt in any computation of the above restriction, any sale and leaseback transaction if:

- the lease is for a period, including renewal rights, of not in excess of three years;
- the sale or transfer of the Principal Property is made within 180 days after its acquisition or within 180 days after the later of:

(1) the completion of construction on, substantial repair to, alteration or development of, or substantial improvement to, such property; and

(2) the commencement of commercial operations thereon;

- the transaction is between Avnet and a Restricted Subsidiary, or between Restricted Subsidiaries;
- Avnet or a Restricted Subsidiary would be entitled to incur a Mortgage on such Principal Property pursuant to clauses (a) through (j) above under Restriction on Secured Debt ; or

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Avnet or a Restricted Subsidiary, within 180 days after the sale or transfer is completed, applies to the retirement of Funded Debt of Avnet ranking on a parity with or senior to the notes or Funded Debt of a Restricted Subsidiary, or to the purchase of other property which will constitute a Principal Property having a fair market value at least equal to the fair market value of the Principal Property leased, an amount equal to the greater of the net proceeds of the sale of the Principal Property or the fair market value (as determined by Avnet s board of directors) of the Principal Property leased at the time of entering into such arrangement (as determined by the board of directors).

Restriction on Mergers and Consolidations

Avnet covenants in the notes, for the benefit of the noteholders, that it will not consolidate with or merge into any other Person, or sell, convey, transfer or lease all or substantially all of its assets unless:

Avnet is the continuing entity or the successor Person is a Person organized under the laws of the United States (including any state thereof and the District of Columbia) and assumes Avnet s obligations under the notes and under the indenture; and

after giving effect to such transaction, no default or event of default under the indenture has occurred or is continuing.

Although there is a limited body of case law interpreting the term substantially all, there is no precise established definition of this phrase under applicable law. Accordingly, in the event the holders of notes attempt to declare an event of default under the indenture and exercise their acceleration rights under the indenture and we contest such action, there can be no assurance of how a court interpreting applicable law would interpret the phrase. It also may be difficult for holders of notes to declare a completed default under the indenture and exercise their acceleration rights.

Definitions

Attributable Debt means, as to any particular lease, the greater of:

the fair market value of the property subject to the lease (as determined by Avnet s board of directors); or

the total net amount of rent required to be paid during the remaining term of the lease, discounted by the weighted average effective interest cost per annum of the outstanding debt securities of all series, compounded semi-annually.

Consolidated Net Assets means total assets after deducting all current liabilities as set forth in the most recent balance sheet of Avnet and its consolidated Subsidiaries and computed in accordance with GAAP.

Funded Debt means:

all indebtedness for money borrowed having a maturity of more than twelve months from the date as of which the determination is made, or having a maturity of twelve months or less but by its terms being renewable or extendible beyond twelve months from such date at the option of the borrower; and

rental obligations payable more than twelve months from such date under leases which are capitalized in accordance with GAAP (such rental obligations to be included as Funded Debt at the amount so capitalized and to be included as an asset for purposes of the definition of Consolidated Net Assets).

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GAAP means generally accepted accounting principles in the United States of America (including, if applicable, International Financial Reporting Standards) as in effect from time to time.

Person means any individual, corporation, partnership, joint venture, association, joint-stock company, trust, unincorporated organization or government or any agency or political subdivision thereof.

Principal Property means any plant, facility or warehouse owned at the original issuance date of the notes or thereafter acquired by Avnet or any Restricted Subsidiary of Avnet which is located within the United States and the gross book value (including related land and improvements thereon and all machinery and equipment included therein without deduction of any depreciation reserves) of which on the date of determination exceeds 2% of Consolidated Net Assets, other than:

- any such manufacturing or processing plant or warehouse or any portion thereof (together with the land on which it is erected and fixtures comprising a part thereof) which is financed by industrial development bonds which are tax exempt pursuant to Section 103 of the Internal Revenue Code (or which receive similar tax treatment under any subsequent amendments thereto or any successor laws thereof or under any other similar statute of the United States);

- any property which, in the opinion of our board of directors, is not of material importance to the total business conducted by Avnet and its consolidated Subsidiaries as an entirety; or

- any portion of a particular property which is similarly found not to be of material importance to the use or operation of such property.

Restricted Subsidiary means a Subsidiary of Avnet (1) substantially all the property of which is located, or substantially all the business of which is carried on, within the United States, and (2) which owns a Principal Property.

Subsidiary means any corporation or other Person more than 50% of the outstanding Voting Stock (measured by voting power rather than number of shares) of which at the date of determination is owned, directly or indirectly, by Avnet and/or by one or more other Subsidiaries.

Voting Stock means capital stock (or equivalent equity interests) of a Person of the class or classes having general voting power under ordinary circumstances to elect at least a majority of the board of directors, managers or trustees of such Person (irrespective of whether or not at the time capital stock (or equivalent equity interests) of any other class or classes has or might have voting power upon the occurrence of any contingency).

Events of Default

The following are events of default with respect to the notes:

(1) a default in the payment of interest on the notes when it becomes due and payable, and a continuance of such default for a period of 30 calendar days;

(2) a default in the payment of the principal on the notes when it becomes due and payable;

(3) a default in the performance, or breach, of any other covenant or warranty in the indenture and the continuance of such default or breach for 90 days after notice; and

(4) certain events of bankruptcy, insolvency or reorganization.

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If an event of default (other than an event of default specified in clause (4) above), occurs and is continuing, either the trustee or the holders of at least 25% in principal amount of the notes of the affected series then outstanding may declare the principal amount of the notes of such series and the accrued and unpaid interest thereon, if any, to be due and payable immediately. If an event of default specified in clause (4) above occurs and is continuing, the principal amount of the notes and the accrued and unpaid interest, if any, thereon will automatically become immediately due and payable without any declaration or other act on the part of the trustee or any holder.

At any time after a declaration of acceleration with respect to the notes of any series has been made and before a judgment or decree for payment of the money due has been obtained, a majority in principal amount of all the notes of that series may rescind and annul the declaration and its consequences if:

(1) Avnet has paid or deposited with the trustee a sum sufficient to pay:

(a) all overdue installments of interest on the notes of the series;

(b) the principal of and premium, if any, on any notes of the series which have become due otherwise than by acceleration and interest thereon at the prescribed rates, if any, set forth in such notes;

(c) interest on overdue interest (to the extent allowed by law) at the prescribed rates, if any, set forth in such notes; and

(d) all amounts due to the trustee under the indenture, including the reasonable compensation, expenses, disbursements, and advances of the Trustee and its agents and counsel; and

(2) any other event of default under the indenture with respect to the notes of that series (other than the nonpayment of principal that has become due solely by declaration of acceleration) has been cured or waived as provided in the indenture.

The indenture provides that the trustee will, within 90 days after the occurrence of a default known to it, give the affected holders of notes notice of all uncured defaults known to it (the term default meaning the events of default specified above without grace periods). However, except in the case of default in the payment of principal of or interest on the notes, the trustee will be protected in withholding such notice if it in good faith determines that the withholding of such notice is in the interest of the affected holders of the notes. In addition, the trustee is not required to provide notice of an event of default to the affected holders of notes specified in clause (3) above until at least 30 days after the event of default occurs.

Avnet must furnish to the trustee annually a statement by certain officers of Avnet certifying that there are no defaults or specifying any default.

The holders of a majority in principal amount of the outstanding notes have the right, with certain limitations, to direct the time, method and place of conducting any proceeding for any remedy available to the trustee or exercising any trust or power conferred on the trustee with respect to the notes, and to waive certain defaults with respect thereto.

The indenture provides that, if an event of default occurs and is continuing, the trustee will exercise such of its rights and powers under the indenture, and use the same degree of care and skill in exercising the same, as a prudent Person would exercise or use under the circumstances in the conduct of such Person s own affairs. Subject to such provisions, the trustee will be under no obligation to exercise any of its rights or powers under the indenture at the request of any of the holders of notes unless they have offered to the trustee reasonable security or indemnity satisfactory to it against the costs, expenses and liabilities which might be incurred by the trustee in compliance with such request.

Modification of the Indenture and Notes

Without the consent of or notice to any holders of the notes, we and the trustee may modify or amend the indenture or the notes for any of the following purposes:

- evidence the succession of another person to us and the assumption by any such successor of the covenants in the indenture and in the notes;
- add to the covenants of Avnet for the benefit of the holders of the notes or to surrender any right or power herein conferred upon Avnet;
- add any additional events of default;
- add to or change any of the provisions of the indenture to such extent as may be necessary to permit or facilitate the issuance of notes in bearer form, registrable or not registrable as to principal, and with or without interest coupons, or to permit or facilitate the issuance of the notes in uncertificated form;
- to add to, change, or eliminate any of the provisions of the indenture in respect of one or more series of notes, provided that any such addition, change, or elimination (i) will neither (A) apply to any notes of any series created prior to such addition, change or elimination and entitled to the benefit of such provision nor (B) modify the rights of the holder of any such notes with respect to such provision or (ii) will become effective only when there are no such notes outstanding;
- to establish the form or terms of notes of any series as permitted under the indenture;
- evidence and provide for the acceptance of appointment hereunder by a successor trustee with respect to the notes and to add to or change any of the provisions of the indenture as may be necessary to provide for or facilitate the administration of the trusts hereunder by more than one trustee; or
- cure any ambiguity, to correct or supplement any provision of the indenture or the notes which may be defective or inconsistent with any other provision of the indenture or the notes, or to make any other provisions with respect to matters or questions arising under the indenture or the notes, provided that such action will not adversely affect the interests of the holders of the notes in any material respect.

With certain exceptions, the indenture and the notes may be modified or amended with the consent of the holders of not less than a majority in principal amount of the notes affected by the modification or amendment. However, no such modification or amendment may be made, without the consent of the holder of each note affected, which would:

- change the stated maturity of the principal of the notes; or reduce the principal amount on the notes or the rate of interest thereon or any premium payable upon the redemption of the notes; or change any place of payment where, or the coin or currency in which, any note or the interest or any premium thereon is payable; or

impair the right to institute suit for the enforcement of any such payment on or after the stated maturity thereof (or, in the case of a redemption, on or after the redemption date); or

reduce the percentage in principal amount of the notes, the consent of holders of which is required to modify or amend the indenture or the notes, or the consent of the holders of which is required for any waiver (of compliance with certain provisions of the indenture subsection or certain defaults therein and their consequences) provided in the indenture; or

modify any of the provisions under Modification of the Indenture and Notes or Events of Default above, except to increase the percentage in principal amount of holders required under any such provision or to provide that certain other provisions of the indenture cannot be modified or waived without the consent of the holder of each outstanding note affected thereby.

Defeasance and Discharge

The indenture provides that Avnet may elect either (i) to terminate its obligations under the indenture, and will be deemed to have been discharged from, any and all of its obligations in respect of the notes (except for certain obligations to register the transfer or exchange of notes, to replace stolen, lost or mutilated notes, to maintain paying agencies and hold monies for payment in trust and to pay the principal of, and any premium or the interest on the notes), which we refer to as legal defeasance, or (ii) to be released from its obligations with respect to certain covenants applicable to the notes, including consolidations and mergers and bankruptcy and insolvency events, and any omission to comply with such obligations will not constitute an event of default with respect to the notes, which we refer to as covenant defeasance.

In order to exercise either legal defeasance or covenant defeasance with respect to any outstanding series of notes issued under the indenture:

Avnet must have irrevocably deposited or caused to be deposited with the trustee, in trust, an amount of money and/or U.S. government obligations (which are defined in the indenture and principally consist of obligations of, or guaranteed by, the United States) or a combination thereof, in each case sufficient, without reinvestment, in the opinion of an independent firm of certified public accountants, to pay and discharge the principal of and any premium and the interest on the notes on the maturity date or on any earlier date on which the notes may be subject to redemption and has given the trustee irrevocable instructions satisfactory to the trustee to give notice to the noteholders of the redemption of the notes, all in accordance with the terms of the indenture and the notes;

Avnet must deliver to the trustee an opinion of counsel to the effect that the holders will not recognize income, gain or loss for federal income tax purposes as a result of such legal defeasance or covenant defeasance and will be subject to federal income tax on the same amounts and in the same manner and at the same times as would have been the case if such legal defeasance or covenant defeasance had not occurred. In the case of legal defeasance, the opinion must refer to and be based upon a ruling received from or published by the Internal Revenue Service or a change in applicable federal income tax law occurring after the date of the indenture;

Avnet must deliver to the trustee (i) an officer s certificate to the effect that the notes, if then listed on any securities exchange, will not be delisted solely as a result of such deposit, and (ii) an officers certificate and an opinion of counsel, each stating that all conditions precedent with respect to such legal defeasance or covenant defeasance have been complied with;

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- no default or event of default must have occurred and be continuing and, no default relating to bankruptcy or insolvency must have occurred and be continuing at any time on or before the 91st day after the date of such deposit, it being understood that this condition will not be deemed satisfied until after the 91st day;

- the legal defeasance or covenant defeasance must not cause the trustee to have a conflicting interest within the meaning of the Trust Indenture Act, assuming all notes are in default within the meaning of such Act;

- the legal defeasance or covenant defeasance must not result in a breach or violation of, or constitute a default under, any other agreement or instrument to which Avnet is a party or by which it is bound; and

- the legal defeasance or covenant defeasance must not result in the trust arising from such deposit constituting an investment company within the meaning of the Investment Company Act of 1940, as amended, unless the trust is registered under the Act or exempt from registration.

Depositary, Global Notes

Notes will be evidenced by one or more global notes deposited with the trustee as custodian for DTC, and registered in the name of Cede & Co. as nominee of DTC.

Record ownership of the global notes may be transferred, in whole or in part, only to another nominee of DTC or to a successor of DTC or its nominee, except as set forth below. An owner of beneficial interests may hold its interests in the global notes directly through DTC if such owner is a participant in DTC, or indirectly through organizations which are direct DTC participants if such owner is not a participant in DTC. Transfers between direct DTC participants will be effected in the ordinary way in accordance with DTC s rules and will be settled in same-day funds. You may also beneficially own interests in the global notes held by DTC through certain banks, brokers, dealers, trust companies and other parties that clear through or maintain a custodial relationship with a direct DTC participant, either directly or indirectly.

So long as Cede & Co., as nominee of DTC, is the registered owner of the global notes, Cede & Co. for all purposes will be considered the sole holder of the global notes. Except as provided below, owners of beneficial interests in the global notes:

- will not be entitled to have certificates registered in their names; and

- will not be considered holders of the global notes.

The laws of some states require that certain persons take physical delivery of securities in definitive form. Consequently, the ability of an owner of a beneficial interest in a global security to transfer the beneficial interest in the global security to such persons may be limited.

We will wire, through the facilities of the trustee, payments of principal, any premium and interest in respect of the global notes to Cede & Co., as nominee of DTC, as the registered owner of the global notes. None of us, the trustee or any paying agent will have any responsibility or be liable for paying amounts due on the global notes to owners of beneficial interests in the global notes.

It is DTC s current practice, upon receipt of any payment on the global notes, to credit participants accounts on the payment date in amounts proportionate to their respective beneficial interests in the notes represented by the global notes, as shown on the records of DTC. Payments by DTC participants to owners of beneficial interests in notes represented by the global notes held through DTC participants will be the responsibility of DTC participants, as is now the case with securities held for the accounts of customers registered in street name.

Because DTC can only act on behalf of DTC participants, who in turn act on behalf of indirect DTC participants and other banks, your ability to pledge your interest in the notes represented by global notes to persons or entities that do not participate in the DTC system, or otherwise take actions in respect of such interest, may be affected by the lack of a physical certificate.

We will issue the notes in definitive certificated form if DTC notifies us that it is unwilling or unable to continue as depositary or DTC ceases to be a clearing agency registered under the Exchange Act and a successor depositary is not appointed by us within 90 days. In addition, beneficial interests in a global note may be exchanged for definitive certificated notes upon request by or on behalf of DTC in accordance with DTC s customary procedures. We may determine at any time and in our sole discretion that notes shall no longer be represented by global notes, in which case we will issue certificates in definitive form in exchange for the global notes.

Neither we nor the trustee (nor any registrar or paying agent under the indenture) will have any responsibility for the performance by DTC or direct or indirect DTC participants of their obligations under the rules and procedures governing their operations. DTC has advised us that it will take any action permitted to be taken by a holder of notes only at the direction of one or more direct DTC participants to whose account with DTC interests in the global notes are credited and only for the principal amount of the notes for which directions have been given.

DTC has advised us as follows: DTC is a limited-purpose trust company organized under the New York Banking Law, a banking organization within the meaning of the New York Banking Law, a member of the Federal Reserve System, a clearing corporation within the meaning of the New York Uniform Commercial Code and a clearing agency registered pursuant to the provisions of Section 17A of the Exchange Act. DTC was created to hold securities for DTC participants and to facilitate the settlement of securities transactions among DTC participants through electronic computerized book-entry changes to the accounts of its participants, thereby eliminating the need for physical movement of securities certificates. Participants include securities brokers and dealers, banks, trust companies and clearing corporations and may include certain other organizations, such as the underwriters of the notes. Certain DTC participants or their representatives, together with other entities, own DTC. Indirect access to the DTC system is available to others such as banks, brokers, dealers and trust companies that clear through, or maintain a custodial relationship with, a participant, either directly or indirectly.

Although DTC has agreed to the foregoing procedures in order to facilitate transfers of interests in the global notes among DTC participants, it is under no obligation to perform or continue to perform such procedures, and such procedures may be discontinued at any time. None of us, the trustee or any of either s respective agents will have any responsibility for the performance by DTC or direct or indirect DTC participants of their obligations under the rules and procedures governing their operations, including maintaining, supervising or reviewing the records relating to or payments made on account of beneficial ownership interests in global notes.

The information in this section concerning DTC and DTC s book-entry system has been obtained from sources that we believe to be reliable, but we take no responsibility for the accuracy thereof.

Euroclear and Clearstream, Luxembourg

You may hold interests in the global notes through Euroclear Bank S.A./N.V., as operator of the Euroclear System (Euroclear) or Clearstream Banking, société anonyme (Clearstream, Luxembourg) in each case, as a participant in DTC.

Euroclear and Clearstream, Luxembourg will hold interests, in each case, on behalf of their participants through customers securities accounts in the names of Euroclear and Clearstream, Luxembourg on the books of their respective depositaries, which will, in turn, hold such interests in customers securities in the depositaries names on DTC s books.

Payments, deliveries, transfers, exchanges, notices and other matters relating to the notes made through Euroclear or Clearstream, Luxembourg must comply with the rules and procedures of those systems. Those systems may change their rules and procedures at any time. We have no control over those systems or their participants, and we take no responsibility for their activities. Transactions between participants in Euroclear or Clearstream, Luxembourg, on the one hand, and other participants in DTC, on the other hand, would also be subject to DTC s rules and procedures.

Investors will be able to make and receive through Euroclear and Clearstream, Luxembourg payments, deliveries, transfers, exchanges, notices and other transactions involving any securities held through those systems only on days when those systems are open for business. Those systems may not be open for business on days when banks, brokers and other institutions are open for business in the United States.

In addition, because of time-zone differences, U.S. investors who hold their interests in the notes through these systems and wish, on a particular day, to transfer their interests, or to receive or make a payment or delivery or exercise any other right with respect to their interests, may find that the transaction will not be effected until the next business day in Luxembourg or Brussels, as applicable. Thus, investors who wish to exercise rights that expire on a particular day may need to act before the expiration date. In addition, investors who hold their interests through both DTC and Euroclear or Clearstream, Luxembourg may need to make special arrangements to finance any purchase or sales of their interests between the U.S. and European clearing systems, and those transactions may settle later than transactions within one clearing system.

Limited Liability of Certain Persons

The indenture provides that none of our past, present or future incorporators, stockholders, directors, officers or employees, or of any successor corporation or any of our affiliates, shall have any personal liability in respect of our obligations under the indenture or the notes by reason of his, her or its status as an incorporator, stockholder, director, officer or employee. Each holder of the notes, by accepting a note, waives and releases all such liability. Such waiver may not be effective to waive liabilities under the U.S. federal securities laws, and it is the view of the SEC that any such waiver is against public policy.

Governing Law

The indenture and the notes will be governed by, and construed in accordance with, the laws of the State of New York.

Information Concerning the Trustee

Wells Fargo Bank, National Association, as trustee under the indenture, has been appointed by us as paying agent and registrar with regard to, and will also serve as DTC s custodian for, the notes. The trustee and/or its affiliates currently, and may from time to time in the future, provide banking and other services to us in exchange for a fee.

The indenture and provisions of the Trust Indenture Act incorporated by reference in the indenture contain certain limitations on the rights of the trustee, should it become our creditor, to obtain payment of claims, or to realize on certain property received in respect of any claim, as security or otherwise. The trustee and its affiliates may engage in, and will be permitted to continue to engage in, other transactions with Avnet and its affiliates; however, if the trustee acquires any conflicting interest (as defined in the Trust Indenture Act), it must eliminate that conflict or resign.

MATERIAL U.S. FEDERAL INCOME TAX CONSIDERATIONS TO NON-U.S. HOLDERS

This section summarizes the material U.S. federal income tax considerations relating to the purchase, ownership, and disposition of the notes by a beneficial owner of notes that, for U.S. federal income tax purposes, is not a U.S. Holder as defined below (a Non-U.S. Holder). This summary does not provide a complete analysis of all potential tax considerations. The information provided below is based on the Internal Revenue Code of 1986, as amended (referred to herein as the Code), Treasury regulations issued under the Code, judicial authority and administrative rulings and practice, all as of the date of this prospectus supplement and all of which are subject to change, possibly on a retroactive basis. The tax considerations of purchasing, owning or disposing of notes could differ from those described below. This summary deals only with purchasers who purchase notes at their issue price, which will equal the first price to the public (not including bond houses, brokers or similar persons or organizations acting in the capacity of underwriters, placement agents or wholesalers) at which a substantial amount of the notes is sold for money, and who hold notes as capital assets within the meaning of Section 1221 of the Code. This summary does not deal with persons in special tax situations, such as financial institutions, insurance companies, regulated investment companies, partnerships and their partners, tax-exempt investors, dealers in securities and currencies, U.S. expatriates or persons holding notes as a position in a straddle, hedge, conversion transaction, or other integrated transaction for tax purposes. Further, this discussion does not address the consequences under U.S. alternative minimum tax rules, U.S. federal estate or gift tax laws, the tax laws of any U.S. state or locality, or any non-U.S. tax laws.

You should consult your tax advisor regarding the application of the U.S. federal, state and local income tax laws to your particular situation and the consequences of U.S. federal estate or gift tax laws and tax treaties.

For purposes of this summary, the term U.S. Holder means a beneficial owner of notes that is, for U.S. federal income tax purposes:

- an individual citizen or resident of the United States;

- a corporation (or any entity treated as a corporation for U.S. federal income tax purposes) created or organized in or under the laws of the United States, any state or the District of Columbia;

- an estate, the income of which is subject to U.S. federal income tax regardless of its source;

- or a trust if, (1) a court within the United States is able to exercise primary supervision over its administration and one or more U.S. persons have authority to control all of its substantial decisions or (2) it has a valid election in effect under applicable Treasury regulations to be treated as a U.S. person.

If a partnership (or an entity or arrangement treated as a partnership for U.S. federal income tax purposes) holds the notes, the U.S. federal income tax treatment of a partner will generally depend on the status of the partner and the tax treatment of the partnership. A partner in a partnership holding the notes should consult its tax advisor with regard to the U.S. federal income tax treatment of owning the notes.

For purposes of this discussion, any interest income and any gain realized on the sale, exchange, retirement or other taxable disposition of a note will be considered U.S. trade or business income if such income or gain is (i) effectively connected with the conduct of a trade or business in the United States and (ii) if a tax treaty applies, attributable to a permanent establishment (or in the case of an individual, to a fixed base) in the United States.

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Treatment of Interest

Subject to the discussion of backup withholding below, a Non-U.S. Holder will not be subject to U.S. federal income tax (or any withholding thereof) in respect of payments of interest on the notes if each of the following requirements is satisfied:

- the interest is not U.S. trade or business income (as defined above).

- the Non-U.S. Holder provides Avnet or its paying agent with a properly completed Internal Revenue Service (IRS) Form W-8BEN (or successor form), or an appropriate substitute form, together with all appropriate attachments, signed under penalties of perjury, identifying the Non-U.S. Holder and stating, among other things, that the Non-U.S. Holder is not a U.S. person. If a note is held through a securities clearing organization, bank or other financial institution that holds customers securities in the ordinary course of its trade or business, this requirement is satisfied if (1) the Non-U.S. Holder provides such a form to the organization or institution and (2) the organization or institution, under penalties of perjury, certifies to Avnet that it has received such a form from the beneficial owner or another intermediary and furnishes Avnet or its paying agent with a copy thereof.

- the Non-U.S. Holder does not actually or constructively own 10% or more of the voting power of Avnet s stock.

- the Non-U.S. Holder is not a controlled foreign corporation (as defined for U.S. federal income tax purposes) that is actually or constructively related to Avnet.

If all of these conditions are not met, a 30% U.S. withholding tax will apply to payments of interest on the notes unless either (1) an applicable income tax treaty reduces or eliminates such tax or (2) the interest is U.S. trade or business income (as defined above) and, in each case, the Non-U.S. Holder complies with applicable certification requirements. In the case of the second exception, the Non-U.S. Holder generally will be subject to U.S. federal income tax with respect to all income from the notes on a net income basis in the same manner as a U.S. Holder. Additionally, Non-U.S. Holders that are corporations could be subject to a branch profits tax on such income. Special procedures contained in Treasury regulations may apply to partnerships, trusts and intermediaries. Avnet urges Non-U.S. Holders to consult their tax advisors for information on the impact of these withholding regulations.

Treatment of Disposition of Notes

Upon the sale, exchange, retirement or other taxable disposition of a note, a Non-U.S. Holder will generally recognize capital gain or loss equal to the difference between (1) the amount of cash and the fair market value of property received (except to the extent such cash or property is attributable to accrued but unpaid interest not previously taken into income) and (2) the Non-U.S. Holder s adjusted tax basis in the note. A Non-U.S. Holder s adjusted tax basis in a note will generally equal the amount the Non-U.S. Holder paid for the note increased, in the case of an accrual basis taxpayer, by any accrued but unpaid interest.

A Non-U.S. Holder generally will not be subject to U.S. federal income tax on gain recognized upon the sale, exchange, retirement or other taxable disposition of a note unless:

- such holder is an individual present in the United States for 183 days or more in the taxable year of the sale, exchange, retirement or other disposition and certain other conditions are met, or

- the gain is U.S. trade or business income (as defined above).

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An individual who is described only in the first bullet point above will be subject to U.S. federal income tax at the rate of 30% on any gain recognized, which may be offset by U.S. source capital losses (even though such individual is not considered a resident of the United States). An individual or corporation that is described in the second bullet point above will be subject to U.S. federal income tax on any gain recognized at the applicable graduated U.S. federal income tax rate in the same manner as a U.S. Holder. In addition, a corporation that is described in the second bullet point above may be subject to a branch profits tax on such gain.

Recent Legislation Relating to Foreign Accounts

Recently enacted legislation imposes withholding taxes on certain types of payments (including interest and gross proceeds of sales) made to foreign financial institutions and certain other non-U.S. entities. Under this legislation, the failure to comply with additional certification, information reporting and other specified requirements could result in withholding tax being imposed on payments of interest and sales proceeds to U.S. Holders who own notes through foreign accounts or foreign intermediaries and certain Non-U.S. Holders. The legislation imposes a 30% withholding tax on interest paid on, or gross proceeds from the sale or other disposition of, notes paid to a foreign financial institution or to a foreign non-financial entity, unless (1) the foreign financial institution undertakes certain diligence and reporting obligations or (2) the foreign non-financial entity either certifies it does not have any substantial U.S. owners or furnishes identifying information regarding each substantial U.S. owner. In addition, if the payee is a foreign financial institution, it must enter into an agreement with the U.S. Treasury requiring, among other things, that it undertake to identify accounts held by certain U.S. persons or U.S.-owned foreign entities, annually report certain information about such accounts and withhold 30% on payments to account holders whose actions prevent it from complying with these reporting and other requirements. The legislation is effective with respect to payments made after December 31, 2012, but recent IRS guidance and proposed Treasury regulations generally indicate that the 30% withholding tax will only apply to payments of interest made after December 31, 2013 and payments of gross proceeds from a sale or other disposition of notes made after December 31, 2016. The legislation also contains a grandfathering provision that exempts from withholding any interest on, or gross proceeds from a disposition of, an obligation that is outstanding on March 18, 2012, and proposed Treasury regulations would extend this grandfathering provision to obligations that are outstanding on January 1, 2013. Foreign financial institutions in a country that enters into an intergovernmental agreement or bilateral agreement with the United States may not be subject to some of the requirements described above. This legislation may be subject to further modification, including finalization of proposed regulations, which may result in additional substantive changes to these rules. Prospective investors should consult their tax advisors regarding this legislation.

Backup Withholding and Information Reporting

When required, we will provide information statements to Non-U.S. Holders and the IRS reporting interest paid with respect to the notes. Payments of the proceeds of the sale or other disposition of the notes to Non-U.S. Holders may also be subject to information reporting unless the Non-U.S. Holder complies with certain certification procedures or otherwise establishes an exemption. Such payments of interest or disposition proceeds may also be subject to backup withholding (currently at a rate of 28%) unless the Non-U.S. Holder is able to establish its exemption from backup withholding (generally through the provision of an IRS Form W-8BEN.)

Backup withholding is not an additional tax. Any amounts withheld from a payment to a holder of notes under the backup withholding rules can be credited against any U.S. federal income tax liability of the holder and may entitle the holder to a refund, provided that the required information is provided to the IRS.

The preceding discussion of certain U.S. federal income tax considerations is for general information only; it is not tax advice. You should consult your own tax advisor regarding the particular U.S. federal, state, local and foreign tax consequences of purchasing, holding and disposing of Avnet s notes, including the consequences of any proposed change in applicable laws.

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UNDERWRITING

Merrill Lynch, Pierce, Fenner & Smith Incorporated and RBS Securities Inc. are joint book-running managers for the offering and are acting as representatives of the underwriters named below. Subject to the terms and conditions of the underwriting agreement dated the date of this prospectus supplement, the underwriters named below have severally agreed to purchase from us, and we have agreed to sell to each underwriter, the principal amount of notes listed opposite their names below at the public offering price less the underwriting discount set forth on the cover page of this prospectus supplement:

Underwriter	Principal Amount of Notes
Merrill Lynch, Pierce, Fenner & Smith Incorporated	$
RBS Securities Inc.	
Total	$

The underwriting agreement provides that the obligations of the several underwriters to purchase the notes offered hereby are subject to certain conditions and that the underwriters will purchase all of the notes offered by this prospectus supplement if any of these notes are purchased.

We have been advised by the representatives of the underwriters that the underwriters propose to offer the notes directly to the public at the public offering price set forth on the cover page of this prospectus supplement and to certain dealers at such price less a concession not in excess of % of the principal amount of the notes. The underwriters may allow, and such dealers may reallow, a concession not in excess of % of the principal amount of the notes to certain other dealers. After the initial public offering, the underwriters may change the offering price and other selling terms.

We estimate that our transaction expenses related to this offering, excluding the underwriting discounts, will be approximately $.

We have agreed to indemnify the underwriters against certain liabilities, including liabilities under the Securities Act, and to contribute to payments the underwriters may be required to make in respect of any of these liabilities.

The notes are a new issue of securities with no established trading market. The notes will not be listed on any securities exchange or on any automated dealer quotation system. The underwriters may make a market in the notes after completion of the offering, but will not be obligated to do so and may discontinue any market-making activities at any time without notice. We cannot assure you as to the liquidity of the trading market for the notes or that an active trading market for the notes will develop. If an active trading market for the notes does not develop, the market price and liquidity of the notes may be adversely affected.

In connection with the offering of the notes, the underwriters may engage in transactions that stabilize, maintain or otherwise affect the price of the notes. Specifically, the underwriters may overallot in connection with the offering, creating a short position. In addition, the underwriters may bid for, and purchase, the notes in the open market to cover short positions or to stabilize the price of the notes. Any of these activities may stabilize or maintain the market price of the notes above independent market levels, but no representation is made hereby that the underwriters will engage in any of those transactions or of the magnitude of any effect that the transactions described above may have on the market price of the notes. The underwriters will not be required to engage in these activities, and if they engage in these activities, they may end any of these activities at any time without notice.

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The underwriters and/or their affiliates have provided and in the future may continue to provide investment banking, commercial banking and/or other financial services, including the provision of Avnet s credit facility, to us in the ordinary course of business for which they have received and may receive customary compensation.

In addition, in the ordinary course of their business activities, the underwriters and their affiliates may make or hold a broad array of investments and actively trade debt and equity securities (or related derivative securities) and financial instruments (including bank loans) for their own account and for the accounts of their customers. Such investments and securities activities may involve securities and/or instruments of ours or our affiliates. Certain of the underwriters or their affiliates that have a lending relationship with us routinely hedge their credit exposure to us consistent with their customary risk management policies. Typically, such underwriters and their affiliates would hedge such exposure by entering into transactions which consist of either the purchase of credit default swaps or the creation of short positions in our securities, including potentially the notes offered hereby. Any such short positions could adversely affect future trading prices of the notes offered hereby. The underwriters and their affiliates may also make investment recommendations and/or publish or express independent research views in respect of such securities or financial instruments and may hold, or recommend to clients that they acquire, long and/or short positions in such securities and instruments.

Conflicts of Interest

Certain affiliates of Merrill Lynch, Pierce, Fenner & Smith Incorporated and RBS Securities Inc. have commitments under Avnet s senior unsecured credit facility and certain affiliates of Merrill Lynch, Pierce, Fenner & Smith Incorporated have commitments under Avnet s accounts receivable securitization program. Consequently, certain affiliates of Merrill Lynch, Pierce, Fenner & Smith Incorporated and RBS Securities Inc. may receive more than 5% of the net proceeds of this offering due to the use of such proceeds to repay amounts outstanding under Avnet s senior unsecured credit facility and/or Avnet s accounts receivable securitization program. See Use of Proceeds. Accordingly, this offering is being made in compliance with the requirements of Rule 5121 of the Financial Industry Regulatory Authority. The underwriters may not confirm sales to discretionary accounts without the prior written approval of the customer.

Selling Restrictions

The notes may be offered and sold in the United States and certain jurisdictions outside the United States in which such offer and sale is permitted.

European Economic Area

Each underwriter has represented and agreed that, in relation to each Member State of the European Economic Area which has implemented the Prospectus Directive (each, a Relevant Member State), with effect from and including the date on which the Prospectus Directive is implemented in that Relevant Member State (the Relevant Implementation Date), it has not made and will not make an offer of notes to the public in that Relevant Member State prior to the publication of a prospectus in relation to the notes which has been approved by the competent authority in that Relevant Member State or, where appropriate, approved in another Relevant Member State and notified to that competent authority in that Relevant Member State, all in accordance with the Prospectus Directive, except that it may, with effect from and including the Relevant Implementation Date, make an offer of notes to the public in that Relevant Member State at any time:

(a) to any legal entity which is a qualified investor as defined in the Prospectus Directive;

(b) to fewer than 150 natural or legal persons (other than qualified investors as defined in the Prospectus Directive), subject to obtaining the prior consent of the representative or representatives nominated by us for any such offer; or

(c) in any other circumstances falling within Article 3(2) of the Prospectus Directive.

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provided that no such offer of notes shall require us or any underwriter to publish a prospectus pursuant to Article 3 of the Prospectus Directive.

For the purposes of this provision, the expression an offer of notes to the public in relation to any notes in any Relevant Member State means the communication in any form and by any means of sufficient information on the terms of the offer and the notes to be offered so as to enable an investor to decide to purchase or subscribe for the notes, as the same may be varied in that Relevant Member State by any measure implementing the Prospectus Directive in that Member State; Prospectus Directive means European Council Directive 2003/71/EC (and amendments thereto, including the 2010 PD Amending Directive) and includes any relevant implementing measure in the Relevant Member State; and 2010 PD Amending Directive means Directive 2010/73/EU.

United Kingdom

This prospectus is only being distributed to, and is only directed at, persons in the United Kingdom that are qualified investors within the meaning of Article 2(1)(e) of the Prospectus Directive (Qualified Investors) that are also (i) investment professionals falling within Article 19(5) of the Financial Services and Markets Act 2000 (Financial Promotion) Order 2005 (the Order) or (ii) high net worth entities, and other persons to whom it may lawfully be communicated, falling within Article 49(2)(a) to (d) of the Order (all such persons together being referred to as relevant persons). This prospectus and its contents are confidential and should not be distributed, published or reproduced (in whole or in part) or disclosed by recipients to any other persons in the United Kingdom. Any person in the United Kingdom that is not a relevant person should not act or rely on this document or any of its contents.

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VALIDITY OF THE NOTES

The validity of the notes will be passed upon for Avnet by David R. Birk, Esq., its Senior Vice President and General Counsel and by Covington & Burling LLP, Washington, District of Columbia. The validity of the notes will be passed upon for the underwriters by Simpson Thacher & Bartlett, LLP, New York, New York.

As of October 31, 2012, Mr. Birk beneficially owned 96,291 shares of Avnet s common stock, which includes 97,026 shares issuable upon exercise of employee stock options within 60 days.

EXPERTS

The consolidated financial statements and financial statement schedule of Avnet, Inc. and subsidiaries as of June 30, 2012 and July 2, 2011, and for each of the years in the three-year period ended June 30, 2012, and management s assessment of the effectiveness of internal control over financial reporting as of June 30, 2012 have been incorporated by reference herein and in the registration statement in reliance upon the report of KPMG LLP, independent registered public accounting firm, incorporated by reference herein, and upon the authority of said firm as experts in accounting and auditing.

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PROSPECTUS

AVNET, INC.

DEBT SECURITIES

COMMON STOCK

PREFERRED STOCK

WARRANTS

DEPOSITARY SHARES

PURCHASE CONTRACTS

UNITS

Avnet, Inc. may from time to time offer to sell debt securities, common stock, preferred stock, warrants, depositary shares, purchase contracts or units. Each time we sell securities pursuant to this prospectus, we will provide a supplement to this prospectus that contains specific information about the offering and the specific terms of the securities offered. You should read this prospectus and the applicable prospectus supplements, including the documents incorporated by reference therein, before investing in our securities.

Avnet s common stock is listed on the New York Stock Exchange under the symbol AVT.

Investing in our securities involves risks. See Risk Factors on page 3 before investing in our securities.

We may offer securities through an underwriting syndicate managed or co-managed by one or more underwriters or dealers, through agents or directly to purchasers. If required, the prospectus supplement for each offering of securities will describe the plan of distribution for that offering.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

The date of this prospectus is November 9, 2012

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ABOUT THIS PROSPECTUS

This prospectus is part of a registration statement we filed with the Securities and Exchange Commission (SEC) using a shelf registration process. We may use this prospectus to sell any one type, or a combination of, the securities described in this prospectus from time to time.

The types of securities that we may offer and sell from time to time pursuant to this prospectus are:

- debt securities;
- common stock;
- preferred stock
- warrants;
- depositary shares;
- purchase contracts; and
- units consisting of any of the securities listed above.

This prospectus only provides you with a general description of the securities that we may offer. Each time we sell securities pursuant to this prospectus, we will describe in a prospectus supplement, which will be delivered with this prospectus, specific information about the offering and the terms of the particular securities offered. The prospectus supplement may also add, update or change the information contained in this prospectus. Before purchasing any securities, you should carefully read both this prospectus and the accompanying prospectus supplement and any free writing prospectus prepared by or on behalf of us, together with the additional information described under Where You Can Find More Information.

For more detailed information about the securities, you should read the exhibits to the registration statement. Those exhibits may be filed with the registration statement or incorporated by reference to earlier SEC filings listed in the registration statement or in subsequent filings that we may make under the Securities Exchange Act of 1934, as amended (the Exchange Act).

Wherever references are made in this prospectus to information that will be included in a prospectus supplement, to the extent permitted by applicable law, rules or regulations, we may instead include such information or add, update or change the information contained in this prospectus by means of a post-effective amendment to the registration statement of which this prospectus is a part, through filings we make with the SEC that are incorporated by reference into the registration statement of which this prospectus is a part or by any other method as may then be permitted under applicable law, rules or regulations.

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When used in this prospectus, the terms Avnet, Inc., the Company, we, our and us refer to Avnet, Inc. and its consolidated subsidiaries, unle otherwise specified or the context otherwise requires.

WHERE YOU CAN FIND MORE INFORMATION

We file annual, quarterly and current reports, proxy statements and other information with the SEC under the Exchange Act. You can inspect and copy these reports, proxy statements and other information at the public reference facilities of the SEC at the SEC s Public Reference Room located at 100 F Street, N.E., Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information on the operation of the Public Reference Room. The SEC also maintains a web site that contains reports, proxy statements and other information regarding registrants that file electronically with the SEC (http://www.sec.gov).

Our annual, quarterly and current reports, proxy statements and other information are also made available free of charge on our investor relations website http://ir.avnet.com/, as soon as reasonably practicable after we electronically file these materials with, or furnish them to, the SEC. Important information, including financial information, analyst presentations, financial news releases, and other material information about us is routinely posted on and accessible at http://ir.avnet.com/. The material posted on our website is not part of this prospectus. You can also inspect reports and other information we file at the office of the New York Stock Exchange, Inc., 20 Broad Street, New York, New York 10005.

We have filed a registration statement and related exhibits with the SEC under the Securities Act of 1933, as amended (the Securities Act). The registration statement contains additional information about us and the securities we may issue. You may inspect the registration statement and exhibits without charge at the office of the SEC at 100 F Street, N.E., Washington, D.C. 20549, and you may obtain copies from the SEC at prescribed rates.

INCORPORATION BY REFERENCE

The SEC allows us to incorporate by reference information into this prospectus, which means that we can disclose important information to you by referring to those documents. The information incorporated by reference is an important part of this prospectus and any information we file later with the SEC will automatically update and supersede this information. We hereby incorporate by reference the following documents or information filed with the SEC (other than, in each case, documents or information deemed to have been furnished and not filed in accordance with SEC rules) and all documents subsequently filed with the SEC under Sections 13(a), 13(c), 14 or 15(d) of the Exchange Act after the date of this prospectus and before the termination of this offering:

- our Annual Report on Form 10-K for the fiscal year ended June 30, 2012;
- our Quarterly Report on Form 10-Q for the fiscal quarter ended September 29, 2012;
- a portion of our Current Report on Form 8-K filed on August 8, 2012 (Item 8.01 only) and our Current Reports on Form 8-K filed on August 10, 2012, August 24, 2012, and November 5, 2012; and
- the description of the Common Stock set forth in the Company s registration statement for such Common Stock filed under the Exchange Act, including any amendment or report filed for the purpose of updating such description.

You may request a copy of these filings at no cost by writing or telephoning us at the following address:

Corporate Secretary

Avnet, Inc.

2211 South 47th Street

Phoenix, Arizona 85034

(480) 643-2000

www.avnet.com

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You should rely only on the information incorporated by reference or provided in this prospectus and the accompanying prospectus supplement. We have not authorized anyone else to provide you with additional or different information.

THE COMPANY

We are one of the world s largest industrial distributors, based on sales, of electronic components, enterprise computer and storage products and embedded subsystems. We create a vital link in the technology supply chain that connects the world s leading electronic component and computer product manufacturers and software developers with a global customer base of original equipment manufacturers, electronic manufacturing services providers, original design manufacturers, and value-added resellers. We distribute electronic components, computer products and software as received from our suppliers or with assembly or other value added by us. Additionally, we provide engineering design, materials management and logistics services, system integration and configuration, and supply chain services that can be customized to meet the requirements of both customers and suppliers.

We have two primary operating groups Electronics Marketing and Technology Solutions. Both operating groups have operations in each of the three major economic regions of the world: the Americas; Europe, the Middle East and Africa; and Asia/Pacific, consisting of Asia, Australia and New Zealand. Each operating group has its own management team led by a group president and includes regional presidents and senior executives within the operating group who manage the various functions within the businesses. Each operating group also has distinct financial reporting that is evaluated at the corporate level on which operating decisions and strategic planning for the Company as a whole are made. Divisions exist within each operating group that serve primarily as sales and marketing units to further streamline the sales and marketing efforts within each operating group and enhance each operating group s ability to work with its customers and suppliers, generally along more specific product lines or geographies. However, each division relies heavily on the support services provided by the operating group as well as centralized support at the corporate level.

Our principal executive offices are located at 2211 South 47th Street, Phoenix, Arizona 85034. Our main telephone number is (480) 643-2000.

RISK FACTORS

Investing in our securities involves risks. Before investing in our securities, you should carefully consider the risk factors described in our most recent Annual Report on Form 10-K, or subsequently filed Quarterly Reports on Form 10-Q and any prospectus supplement, as well as risks described in Management s Discussion and Analysis of Financial Condition and Results of Operations and cautionary notes regarding forward-looking statements included or incorporated by reference herein, together with all other information included in this prospectus, any prospectus supplement and the documents we incorporate by reference. These risks could materially affect our business, results of operations or financial condition and cause the value of our securities to decline. You could lose all or part of your investment.

USE OF PROCEEDS

Unless the applicable prospectus supplement indicates otherwise, we intend to use net proceeds from the sale of the securities for general corporate purposes.

We may temporarily invest funds that are not immediately needed for these purposes in short-term securities.

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DESCRIPTION OF SECURITIES

We will describe the specific terms of any securities to be offered in the applicable prospectus supplement. Debt securities offered under this prospectus will be governed by a document called an Indenture. Unless we specify otherwise in the applicable prospectus supplement, the debt securities will be issued under an Indenture, dated as of June 22, 2010, between us and Wells Fargo Bank, National Association, which acts as Trustee. In addition to the material terms of the Indenture described in the applicable prospectus supplement, you should review the Indenture, which is incorporated by reference as an exhibit to the registration statement of which this prospectus is a part.

PLAN OF DISTRIBUTION

We may sell the offered securities:

- through underwriters or dealers;
- through agents;
- directly to one or more purchasers; or
- through a number of direct sales or auctions performed by utilizing the Internet or a bidding or ordering system.

We may distribute the securities from time to time in one or more transactions at a fixed price or prices, which may be changed, or at market prices prevailing at the time of sale, at prices related to the prevailing market prices or at negotiated prices.

Sale Through Underwriters or Dealers

If we use underwriters or dealers in the sale of offered securities, such underwriters or dealers will acquire the securities for their own account. The underwriters or dealers may resell the securities in one or more transactions, including negotiated transactions, at a fixed public offering price or at varying prices determined at the time of sale. The obligations of the underwriters or dealers to purchase the securities will be subject to certain conditions. The underwriters or dealers will be obligated to purchase all the securities of the series offered if any of the securities are purchased. The underwriters or dealers may change from time to time any initial public offering price and any discounts or concessions allowed or re-allowed or paid to dealers.

Sale Through Agents

We may sell offered securities through agents designated by us. Unless indicated in the applicable prospectus supplement, the agents will agree to use their reasonable best efforts to solicit purchases for the period of their appointment.

Direct Sales

We may also sell offered securities directly. In this case, no underwriters or agents would be involved.

Sale Through the Internet

We may from time to time offer securities directly to the public, with or without the involvement of agents, underwriters or dealers, and may utilize the Internet or another electronic bidding or ordering system for the pricing and allocation of such securities. Such a system may allow bidders to directly participate, through electronic access to an auction site, by submitting conditional offers to buy that are subject to acceptance by us, and which may directly affect the price or other terms at which such securities are sold.

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Such a bidding or ordering system may present to each bidder, on a real-time basis, relevant information to assist the bidder in making a bid, such as the clearing spread at which the offering would be sold, based on the bids submitted, and whether a bidder s individual bids would be accepted, prorated or rejected. Typically the clearing spread will be indicated as a number of basis points above an index treasury note. Other pricing methods may also be used. Upon completion of such an auction process, securities will be allocated based on prices bid, terms of bid or other factors.

The final offering price at which securities would be sold and the allocation of securities among bidders, would be based in whole or in part on the results of the Internet bidding process or auction. Many variations of Internet auction or pricing and allocation systems are likely to be developed in the future, and we may utilize such systems in connection with the sale of securities. The specific rules of such an auction would be distributed to potential bidders in an applicable prospectus supplement.

If an offering is made using such bidding or ordering system you should review the auction rules, as described in the applicable prospectus supplement, for a more detailed description of such offering procedures.

General Information

Underwriters, dealers and agents that participate in the distribution of the offered securities may be underwriters as defined in the Securities Act, and any discounts or commissions received by them from us and any profit on the resale of the offered securities by them may be treated as underwriting discounts and commissions under the Securities Act. We will identify any underwriters, dealers or agents, and describe their compensation, in the applicable prospectus supplement.

We may have agreements with the underwriters, dealers and agents to indemnify them against certain civil liabilities, including liabilities under the Securities Act, or to contribute with respect to payments which the underwriters, dealers or agents may be required to make. Underwriters, dealers and agents may engage in transactions with, or perform services for, us or our subsidiaries in the ordinary course of their businesses.

VALIDITY OF SECURITIES

The validity of any offered securities will be passed upon for Avnet by David R. Birk, its Senior Vice President and General Counsel. Mr. Birk is the beneficial owner of shares of our common stock, including shares issuable upon exercise of employee stock options. Certain legal matters with respect to the offered securities will be passed upon for the underwriters, dealers or agents, if any, by their counsel.

EXPERTS

The consolidated financial statements and financial statement schedule of Avnet, Inc. and subsidiaries as of June 30, 2012 and July 2, 2011, and for each of the years in the three-year period ended June 30, 2012, and management s assessment of the effectiveness of internal control over financial reporting as of June 30, 2012 have been incorporated by reference herein and in the registration statement in reliance upon the report of KPMG LLP, independent registered public accounting firm, incorporated by reference herein, and upon the authority of said firm as experts in accounting and auditing.

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Avnet, Inc.

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2014

2013

(in millions)

(in millions)
Energy-related derivatives:
Other regulatory assets, current
$
(32
)

$
(3
)
Other current liabilities
$
1

$
5

Other regulatory assets, deferred
(21

)

(5
)
Other regulatory liabilities, deferred
—

2

Total energy-related derivative gains (losses)

$
(53
)

$
(8
)

$
1

$
7

For the years ended December 31, 2014, 2013, and 2012, the pre-tax effect of interest rate derivatives designated as cash flow hedging instruments on the statements of income was as follows:

Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Recognized in OCI on Derivative (Effective Portion)			Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)			
					Amount		
Derivative Category	2014	2013	2012	Statements of Income Location	2014	2013	2012
	(in millions)				(in millions)		
Interest rate derivatives	$(8)	$—	$(18)	Interest expense, net of amounts capitalized	$(3)	$(3)	$(3)

There was no material ineffectiveness recorded in earnings for any period presented.
For the years ended December 31, 2014, 2013, and 2012, the pre-tax effect of energy-related derivatives not designated as hedging instruments on the statements of income was not material.
Contingent Features
The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in

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the event of various credit rating changes of certain affiliated companies. At December 31, 2014, the Company's collateral posted with its derivative counterparties was not material.

At December 31, 2014, the fair value of derivative liabilities with contingent features was $18 million. However, because of joint and several liability features underlying these derivatives, the maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $54 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.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P or with counterparties who have posted collateral to cover potential credit exposure. The Company has also established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk. Therefore, the Company does not anticipate a material adverse effect on the financial statements as a result of counterparty nonperformance.

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NOTES (continued)
Alabama Power Company 2014 Annual Report

12. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)
Summarized quarterly financial information for 2014 and 2013 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred and Preference Stock
	(in millions)		
March 2014	$1,508	$381	$187
June 2014	1,437	357	173
September 2014	1,669	520	282
December 2014	1,328	267	119
March 2013	$1,308	$307	$141
June 2013	1,392	357	173
September 2013	1,604	500	258
December 2013	1,314	312	140

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

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SELECTED FINANCIAL AND OPERATING DATA 2010-2014
Alabama Power Company 2014 Annual Report

	2014	2013	2012	2011	2010
Operating Revenues (in millions)	$5,942	$5,618	$5,520	$5,702	$5,976
Net Income After Dividends on Preferred and Preference Stock (in millions)	$761	$712	$704	$708	$707
Cash Dividends on Common Stock (in millions)	$550	$644	$684	$774	$586
Return on Average Common Equity (percent)	13.52	13.07	13.10	13.19	13.31
Total Assets (in millions)	$20,552	$19,251	$18,712	$18,477	$17,994
Gross Property Additions (in millions)	$1,543	$1,204	$940	$1,016	$956
Capitalization (in millions):					
Common stock equity	$5,752	$5,502	$5,398	$5,342	$5,393
Preference stock	343	343	343	343	343
Redeemable preferred stock	342	342	342	342	342
Long-term debt	6,176	6,233	5,929	5,632	5,987
Total (excluding amounts due within one year)	$12,613	$12,420	$12,012	$11,659	$12,065
Capitalization Ratios (percent):					
Common stock equity	45.6	44.3	44.9	45.8	44.7
Preference stock	2.7	2.8	2.9	2.9	2.9
Redeemable preferred stock	2.7	2.7	2.8	2.9	2.8
Long-term debt	49.0	50.2	49.4	48.4	49.6
Total (excluding amounts due within one year)	100.0	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	1,247,061	1,241,998	1,237,730	1,231,574	1,235,128
Commercial	197,082	196,209	196,177	196,270	197,336
Industrial	6,032	5,851	5,839	5,844	5,770
Other	753	751	748	746	782
Total	1,450,928	1,444,809	1,440,494	1,434,434	1,439,016
Employees (year-end)	6,935	6,896	6,778	6,632	6,552

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SELECTED FINANCIAL AND OPERATING DATA 2010-2014 (continued)
Alabama Power Company 2014 Annual Report

	2014	2013	2012	2011	2010
Operating Revenues (in millions):					
Residential	$2,209	$2,079	$2,068	$2,144	$2,283
Commercial	1,533	1,477	1,491	1,495	1,535
Industrial	1,480	1,369	1,346	1,306	1,231
Other	27	27	28	27	27
Total retail	5,249	4,952	4,933	4,972	5,076
Wholesale — non-affiliates	281	248	277	287	465
Wholesale — affiliates	189	212	111	244	236
Total revenues from sales of electricity	5,719	5,412	5,321	5,503	5,777
Other revenues	223	206	199	199	199
Total	$5,942	$5,618	$5,520	$5,702	$5,976
Kilowatt-Hour Sales (in millions):					
Residential	18,726	17,920	17,612	18,650	20,417
Commercial	14,118	13,892	13,963	14,173	14,719
Industrial	23,799	22,904	22,158	21,666	20,622
Other	211	211	214	214	216
Total retail	56,854	54,927	53,947	54,703	55,974
Wholesale — non-affiliates	3,588	3,711	4,196	4,330	8,655
Wholesale — affiliates	6,713	7,672	4,279	7,211	6,074
Total	67,155	66,310	62,422	66,244	70,703
Average Revenue Per Kilowatt-Hour (cents):					
Residential	11.80	11.60	11.74	11.50	11.18
Commercial	10.86	10.63	10.68	10.55	10.43
Industrial	6.22	5.98	6.07	6.03	5.97
Total retail	9.23	9.02	9.14	9.09	9.07
Wholesale	4.56	4.04	4.58	4.60	4.76
Total sales	8.52	8.16	8.52	8.31	8.17
Residential Average Annual Kilowatt-Hour Use Per Customer	15,051	14,451	14,252	15,138	16,570
Residential Average Annual Revenue Per Customer	$1,775	$1,676	$1,674	$1,740	$1,853
Plant Nameplate Capacity Ratings (year-end) (megawatts)	12,222	12,222	12,222	12,222	12,222
Maximum Peak-Hour Demand (megawatts):					
Winter	11,761	9,347	10,285	11,553	11,349
Summer	11,054	10,692	11,096	11,500	11,488
Annual Load Factor (percent)	61.4	64.9	61.3	60.6	62.6
Plant Availability (percent)*:					
Fossil-steam	82.5	87.3	88.6	88.7	92.9
Nuclear	93.3	90.7	94.5	94.7	88.4
Source of Energy Supply (percent):					
Coal	49.0	50.0	48.2	52.5	56.6
Nuclear	20.7	20.3	22.6	20.8	17.7
Hydro	5.5	8.1	4.1	4.6	5.0
Gas	15.4	15.7	16.8	15.3	14.0

Purchased power —					
From non-affiliates	3.6	2.9	2.0	0.9	1.6
From affiliates	5.8	3.0	6.3	5.9	5.1
Total	100.0	100.0	100.0	100.0	100.0

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

GEORGIA POWER COMPANY
FINANCIAL SECTION

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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Georgia Power Company 2014 Annual Report
The management of Georgia Power Company (the Company) is responsible for establishing and maintaining an adequate system of internal control over financial reporting as required by the Sarbanes-Oxley Act of 2002 and as defined in Exchange Act Rule 13a-15(f). A control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met.
Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2014.
/s/ W. Paul Bowers
W. Paul Bowers
Chairman, President, and Chief Executive Officer
/s/ W. Ron Hinson
W. Ron Hinson
Executive Vice President, Chief Financial Officer, and Treasurer
March 2, 2015

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Georgia Power Company

We have audited the accompanying balance sheets and statements of capitalization of Georgia Power Company (the Company) (a wholly owned subsidiary of The Southern Company) as of December 31, 2014 and 2013, and the related statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2014. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements (pages II-228 to II-277) present fairly, in all material respects, the financial position of Georgia Power Company as of December 31, 2014 and 2013, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
March 2, 2015

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DEFINITIONS

Term	Meaning
2013 ARP	Alternative Rate Plan approved by the Georgia PSC for Georgia Power for the years 2014 through 2016
AFUDC	Allowance for funds used during construction
Alabama Power	Alabama Power Company
ASC	Accounting Standards Codification
CCR	Coal combustion residuals
Clean Air Act	Clean Air Act Amendments of 1990
CO_2	Carbon dioxide
CWIP	Construction work in progress
DOE	U.S. Department of Energy
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FFB	Federal Financing Bank
GAAP	Generally accepted accounting principles
Gulf Power	Gulf Power Company
IRS	Internal Revenue Service
ITC	Investment tax credit
KWH	Kilowatt-hour
LIBOR	London Interbank Offered Rate
Mississippi Power	Mississippi Power Company
mmBtu	Million British thermal units
Moody's	Moody's Investors Service, Inc.
MW	Megawatt
NCCR	Nuclear Construction Cost Recovery
NRC	U.S. Nuclear Regulatory Commission
OCI	Other comprehensive income
Plant Vogtle Units 3 and 4	Two new nuclear generating units under construction at Plant Vogtle
power pool	The operating arrangement whereby the integrated generating resources of the traditional operating companies and Southern Power Company are subject to joint commitment and dispatch in order to serve their combined load obligations
PPA	Power purchase agreement
PSC	Public Service Commission
ROE	Return on equity
S&P	Standard and Poor's Rating Services, a division of The McGraw Hill Companies, Inc.
SCS	Southern Company Services, Inc. (the Southern Company system service company)
SEC	U.S. Securities and Exchange Commission
SEGCO	Southern Electric Generating Company
Southern Company system	The Southern Company, the traditional operating companies, Southern Power, SEGCO, Southern Nuclear, SCS, SouthernLINC Wireless, and other subsidiaries
SouthernLINC Wireless	Southern Communications Services, Inc.
Southern Nuclear	Southern Nuclear Operating Company, Inc.
Southern Power	Southern Power Company and its subsidiaries
traditional operating companies	Alabama Power, Georgia Power Company, Gulf Power, and Mississippi Power

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MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Georgia Power Company 2014 Annual Report
OVERVIEW
Business Activities
Georgia Power Company (the Company) operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located within the State of Georgia and to wholesale customers in the Southeast.
Many factors affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the ability to maintain a constructive regulatory environment, to maintain and grow energy sales, and to effectively manage and secure timely recovery of costs. These costs include those related to projected long-term demand growth, increasingly stringent environmental standards, reliability, and fuel. In addition, the Company is currently constructing Plant Vogtle Units 3 and 4 and will own a 45.7% interest in these two nuclear generating units to increase its generation diversity and meet future supply needs. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future.
In December 2013, the Georgia PSC approved the 2013 ARP for the years 2014 through 2016 including a base rate increase of approximately $110 million for 2014 and required compliance filings for both 2015 and 2016 to review base rate increases for those respective years. On February 19, 2015, the Georgia PSC completed its review of the Company's October 3, 2014 compliance filing for 2015 and approved a base rate increase of approximately $136 million for that year. The 2016 base rate increase, which was approved in the 2013 ARP, will be determined through a compliance filing expected to be filed in late 2015, and will be subject to review by the Georgia PSC. The Company is scheduled to file its next base rate case by July 1, 2016. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Rate Plans" herein for additional information.
Key Performance Indicators
The Company continues to focus on several key performance indicators, including customer satisfaction, plant availability, system reliability, the execution of major construction projects, and net income after dividends on preferred and preference stock. The Company's financial success is directly tied to customer satisfaction. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys to evaluate the Company's results and generally targets the top quartile of these surveys in measuring performance, which the Company achieved during 2014.
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 Company's 2014 Peak Season EFOR of 1.93% was better than the target. Transmission and distribution system reliability performance is measured by the frequency and duration of outages, with performance targets set based on historical performance. The Company's 2014 performance was better than the target for these transmission and distribution reliability measures.
The Company uses net income after dividends on preferred and preference stock as the primary measure of the Company's financial performance. In 2014, the Company achieved its targeted net income after dividends on preferred and preference stock. See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance.
Earnings
The Company's 2014 net income after dividends on preferred and preference stock was $1.2 billion, representing a $51 million, or 4.3%, increase over the previous year. The increase was due primarily to an increase in base retail revenues effective January 1, 2014 as authorized under the 2013 ARP and colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013, partially offset by higher non-fuel operations and maintenance expenses.
The Company's 2013 net income after dividends on preferred and preference stock was $1.2 billion, representing a $6 million, or 0.5%, increase over the previous year. The increase was due primarily to an increase related to retail

revenue rate effects, partially offset by milder weather in 2013, an increase in depreciation and amortization, and higher income taxes.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Georgia Power Company 2014 Annual Report

RESULTS OF OPERATIONS
A condensed income statement for the Company follows:

	Amount	Increase (Decrease) from Prior Year	
	2014	2014	2013
	(in millions)		
Operating revenues	$8,988	$714	$276
Fuel	2,547	240	256
Purchased power	988	104	(97)
Other operations and maintenance	1,902	248	10
Depreciation and amortization	846	39	62
Taxes other than income taxes	409	27	8
Total operating expenses	6,692	658	239
Operating income	2,296	56	37
Allowance for equity funds used during construction	45	15	(23)
Interest expense, net of amounts capitalized	348	(13)	(5)
Other income (expense), net	(22)	(27)	22
Income taxes	729	6	35
Net income	1,242	51	6
Dividends on preferred and preference stock	17	—	—
Net income after dividends on preferred and preference stock	$1,225	$51	$6

Operating Revenues
Operating revenues for 2014 were $9.0 billion, reflecting a $714 million increase from 2013. Details of operating revenues were as follows:

	Amount	
	2014	2013
	(in millions)	
Retail — prior year	$7,620	$7,362
Estimated change resulting from —		
Rates and pricing	183	137
Sales growth (decline)	21	(5)
Weather	139	(61)
Fuel cost recovery	277	187
Retail — current year	8,240	7,620
Wholesale revenues —		
Non-affiliates	335	281
Affiliates	42	20
Total wholesale revenues	377	301
Other operating revenues	371	353
Total operating revenues	$8,988	$8,274
Percent change	8.6%	3.5%

Retail base revenues of $5.2 billion in 2014 increased $343 million, or 7.1%, compared to 2013. The significant factors driving this change are shown in the preceding table. The increase in rates and pricing was primarily due to base tariff increases effective January 1, 2014, as approved by the Georgia PSC in the 2013 ARP, and increases in collections for financing costs related to the

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construction of Plant Vogtle Units 3 and 4 through the NCCR tariff as well as higher contributions from market-driven rates from commercial and industrial customers. In 2014, residential base revenues increased $163 million, or 7.6%, commercial base revenues increased $108 million, or 5.5%, and industrial base revenues increased $74 million, or 11.1%, compared to 2013.

Retail base revenues of $4.9 billion in 2013 increased $71 million, or 1.5%, compared to 2012. The significant factors driving this change are shown in the preceding table. The increase in rates and pricing was primarily due to base tariff increases effective April 1, 2012 and January 1, 2013, as approved by the Georgia PSC, related to placing new generating units at Plant McDonough-Atkinson in service and collecting financing costs related to the construction of Plant Vogtle Units 3 and 4 through the NCCR tariff, as well as higher contributions from market-driven rates from commercial and industrial customers. The increase was partially offset by milder weather in 2013 as compared to 2012. In 2013, residential base revenues decreased $3 million, or 0.1%, commercial base revenues increased $43 million, or 2.2%, and industrial base revenues increased $28 million, or 4.4%, compared to 2012. Residential usage continued to be impacted by economic uncertainty, modest economic growth, and energy efficiency efforts.

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

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

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

	2014	2013	2012
	(in millions)		
Capacity and other	$164	$174	$177
Energy	171	107	104
Total non-affiliated	$335	$281	$281

Wholesale capacity revenues from PPAs are recognized either on a levelized basis over the appropriate contract period or the amounts billable under the contract terms and provide for recovery of fixed costs and a return on investment.

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

Wholesale revenues from other non-affiliated sales increased $54 million, or 19.2%, in 2014 and were flat in 2013 as compared to 2012. The increase in 2014 was primarily due to increased demand resulting from colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013 and the lower cost of Company-owned generation compared to the market cost of available energy. The decrease in capacity revenues reflects the expiration of a wholesale contract in December 2013 and the removal of Plant Branch Unit 2 capacity from contracts following the unit's retirement in September 2013.

Wholesale revenues from sales to affiliated companies will vary depending on demand and the availability and cost of generating resources at each company. These affiliate sales are made in accordance with the Intercompany Interchange Contract (IIC), as approved by the FERC. These transactions do not have a significant impact on earnings since this energy is generally sold at marginal cost. In 2014, wholesale revenues from sales to affiliates increased $22 million as compared to 2013 due to colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013 and the lower cost of Company-owned generation. Wholesale revenues from sales to affiliated companies remained flat in 2013 as compared to 2012.

Other operating revenues increased $18 million, or 5.1%, in 2014 from the prior year primarily due to $7 million in transmission service revenues, $5 million of solar application fee revenues, and $5 million in outdoor lighting revenues. Other operating revenues increased $18 million, or 5.4%, in 2013 from the prior year primarily due to higher revenues from transmission, pole attachments, and outdoor lighting.

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Energy Sales
Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2014 and the percent change from the prior year were as follows:

	Total KWHs	Total KWH Percent Change				Weather-Adjusted Percent Change			
	2014	2014		2013		2014		2013*	
	(in billions)								
Residential	27.1	6.5	%	(1.0	)%	0.5	%	0.1	%
Commercial	32.4	1.4		(0.9	)	(0.2	)	(0.2	)
Industrial	23.6	2.0		—		1.5		0.7	
Other	0.7	0.5		(1.8	)	0.3		(1.8	)
Total retail	83.8	3.2		(0.7	)	0.5	%	0.1	%
Wholesale									
Non-affiliates	4.3	42.6		3.3					
Affiliates	1.1	125.4		(17.4	)				
Total wholesale	5.4	54.2		(0.2	)				
Total energy sales	89.2	5.3	%	(0.7	)%				

* In the first quarter 2012, the Company began using new actual advanced meter data to compute unbilled revenues. The weather-adjusted KWH sales variances shown above reflect an adjustment to the estimated allocation of the Company's unbilled January 2012 KWH sales among customer classes that is consistent with the actual allocation in 2013. Without this adjustment, 2013 weather-adjusted residential KWH sales decreased 0.4% as compared to 2012 while 2013 weather-adjusted commercial KWH sales increased 0.2% as compared to 2012.

Changes in retail energy sales are generally the result of changes in electricity usage by customers, changes in weather, and changes in the number of customers.

In 2014, KWH sales for residential and commercial customer classes increased compared to 2013 primarily due to colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013 and customer growth, partially offset by decreased customer usage. Industrial sales increased in 2014 compared to 2013. Increased demand in the paper, textiles, and stone, clay, and glass sectors were the main contributors to the increase in industrial sales in 2014 compared to 2013. Weather adjusted commercial KWH sales decreased by 0.2% as a result of decreased customer usage, largely offset by customer growth. Weather adjusted residential KWH sales increased by 0.5% as a result of customer growth, largely offset by decreased customer usage. Household income, one of the primary drivers of residential customer usage, was flat in 2014.

In 2013, KWH sales for residential and commercial customer classes decreased compared to 2012 primarily due to milder weather in 2013. Industrial sales were flat in 2013 compared to 2012. Increased demand in the paper, textiles, and stone, clay, and glass sectors were the main contributors to the increase in weather-adjusted industrial sales in 2013 compared to 2012.

See "Operating Revenues" above for a discussion of significant changes in wholesale sales to non-affiliates and affiliated companies.

Fuel and Purchased Power Expenses
Fuel costs constitute the single largest expense for the Company. The mix of fuel sources for generation of electricity is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units. Additionally, the Company purchases a portion of its electricity needs from the wholesale market.

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

	2014	2013	2012
Total generation (billions of KWHs)	69.9	66.8	59.8
Total purchased power (billions of KWHs)	23.1	21.4	28.7
Sources of generation (percent) —			
Coal	41	35	39
Nuclear	22	23	27
Gas	35	39	33
Hydro	2	3	1
Cost of fuel, generated (cents per net KWH) —			
Coal	4.52	4.92	4.63
Nuclear	0.90	0.91	0.87
Gas	3.67	3.33	3.02
Average cost of fuel, generated (cents per net KWH)	3.40	3.32	3.07
Average cost of purchased power (cents per net KWH)*	5.20	4.83	4.24

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

Fuel and purchased power expenses were $3.5 billion in 2014, an increase of $344 million, or 10.8%, compared to 2013. The increase was primarily due to a $292 million increase in the volume of KWHs generated and purchased due to colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013 driving higher customer demand and an increase of $84 million in the average cost of purchased power primarily due to higher natural gas prices, partially offset by a $32 million decrease in the average cost of fuel primarily due to lower coal prices.

Fuel and purchased power expenses were $3.2 billion in 2013, an increase of $159 million, or 5.2%, compared to 2012. The increase was primarily due to a $284 million increase in the average cost of fuel and purchased power primarily due to higher natural gas prices and a $185 million increase due to an increase in the volume of KWHs generated, partially offset by a $310 million decrease due to a decrease in the volume of KWHs purchased, as the cost of Company-owned generation was lower than the market cost of available energy.

Fuel and purchased power energy transactions do not have a significant impact on earnings since these fuel expenses are generally offset by fuel revenues through the Company's fuel cost recovery mechanism. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Fuel Cost Recovery" herein for additional information.

Fuel

Fuel expense was $2.5 billion in 2014, an increase of $240 million, or 10.4%, compared to 2013. The increase was primarily due to an increase of 5.7% in the volume of KWHs generated as a result of colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013 driving higher customer demand and a 2.4% increase in the average cost of fuel per KWH generated primarily due to higher natural gas prices, partially offset by lower coal prices. Fuel expense was $2.3 billion in 2013, an increase of $256 million, or 12.5%, compared to 2012. The increase was primarily due to a 9.9% increase in the volume of KWHs generated as a result of higher prices for purchased power and an 8.1% increase in the average cost of fuel per KWH generated for all types of fuel generation, partially offset by a 191.0% increase in the volume of KWHs generated by hydro facilities resulting from greater rainfall.

Purchased Power - Non-Affiliates

Purchased power expense from non-affiliates was $287 million in 2014, an increase of $63 million, or 28.1%, compared to 2013. The increase was primarily due to a 6.1% increase in the average cost per KWH purchased primarily resulting from higher natural gas prices and a 22.0% increase in the volume of KWHs purchased to meet higher customer demand resulting from colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013. Purchased power expense from non-affiliates was $224 million in 2013, a decrease of $91 million, or 28.9%, compared to 2012. The decrease was primarily due to a 52.0% decrease in the volume of KWHs purchased as the cost of Company-owned generation was lower than the market cost of available energy, partially offset by an increase of 41.5% in the average cost per KWH purchased primarily due to higher fuel prices.

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

Purchased Power - Affiliates

Purchased power expense from affiliates was $701 million in 2014, an increase of $41 million, or 6.2%, compared to 2013. The increase was primarily due to an increase of 5.8% in the average cost per KWH purchased reflecting higher natural gas prices and a 5.6% increase in the volume of KWHs purchased to meet higher customer demand resulting from colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013. Purchased power expense from affiliates was $660 million in 2013, a decrease of $6 million, or 0.9%, compared to 2012. The decrease was primarily due to an 18.4% decrease in the volume of KWHs purchased as the Company’s units generally dispatched at a lower cost than other Southern Company system resources, partially offset by a 12.6% increase in the average cost per KWH purchased reflecting higher fuel prices.

Energy purchases from affiliates will vary depending on the demand and the availability and cost of generating resources at each company within the Southern Company system. These purchases are made in accordance with the IIC or other contractual agreements, all as approved by the FERC.

Other Operations and Maintenance Expenses

In 2014, other operations and maintenance expenses increased $248 million, or 15.0%, compared to 2013. The increase was primarily due to increases of $74 million in transmission and distribution overhead line maintenance expenses, $58 million in generation expense to meet higher demand, $52 million in scheduled outage-related costs, $35 million in customer assistance expenses related to customer incentive and demand-side management costs, and $11 million in the storm damage accrual as authorized in the 2013 ARP.

In 2013, other operations and maintenance expenses increased $10 million, or 0.6%, compared to 2012. The increase was primarily due to an increase of $33 million in pension and other employee benefit-related expenses and $13 million in transmission system load expense resulting from billing adjustments with integrated transmission system owners, partially offset by a decrease of $38 million in fossil generating expenses due to cost containment and outage timing to offset milder weather in 2013 as compared to 2012 and the effect of economic uncertainty.

Depreciation and Amortization

Depreciation and amortization increased $39 million, or 4.8%, in 2014 compared to 2013. The increase was primarily due to decreases of $36 million and $17 million in amortization of regulatory liabilities related to state income tax credits that was completed in December 2013 and other cost of removal obligations as authorized in the 2013 ARP, respectively, partially offset by a decrease of $14 million in depreciation and amortization also as authorized in the 2013 ARP.

Depreciation and amortization increased $62 million, or 8.3%, in 2013 compared to 2012. The increase was primarily due to an increase of $64 million in depreciation on additional plant in service due to the completion of Plant McDonough-Atkinson Units 5 and 6 in 2012 and depreciation and amortization resulting from certain coal unit retirement decisions (with respect to the portion of such units dedicated to wholesale service). The increase was partially offset by a net reduction in amortization primarily related to amortization of the regulatory liability previously established for state income tax credits, as authorized by the Georgia PSC.

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

Taxes Other Than Income Taxes

In 2014, taxes other than income taxes increased $27 million, or 7.1%, compared to 2013. The increase was primarily due to increases of $24 million in municipal franchise fees related to higher retail revenues and $9 million in payroll taxes, partially offset by a $6 million decrease in property taxes.

In 2013, taxes other than income taxes increased $8 million, or 2.1%, compared to 2012. The increase was primarily due to an increase in property taxes.

Allowance for Equity Funds Used During Construction

AFUDC equity increased $15 million, or 50.0%, in 2014 compared to the prior year primarily due to an increase in construction related to ongoing environmental and transmission projects. AFUDC equity decreased $23 million, or 43.4%, in 2013 compared to the prior year primarily due to the completion of Plant McDonough-Atkinson Units 5 and 6 in 2012.

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Interest Expense, Net of Amounts Capitalized

In 2014, interest expense, net of amounts capitalized decreased $13 million, or 3.6%, from the prior year. The decrease was primarily due to a $40 million decrease in interest on long-term debt resulting from redemptions and refinancing of long-term debt at lower interest rates and a $4 million increase in interest capitalized as a result of increased construction activity, partially offset by a $32 million increase in interest on outstanding long-term debt borrowings from the FFB.

In 2013, interest expense, net of amounts capitalized decreased $5 million, or 1.4%, from the prior year. The decrease was primarily due to a $21 million decrease in interest on long-term debt as a result of refinancing activity, partially offset by an $8 million decrease in AFUDC debt primarily due to the completion of Plant McDonough Units 5 and 6 discussed previously and a $9 million increase resulting from the conclusion of certain state and federal income tax audits that reduced interest expense in 2012.

Other Income (Expense), net

In 2014, other income (expense), net decreased $27 million from the prior year primarily due to a $9 million increase in donations and an $8 million decrease in wholesale operating fee revenue. In 2013, other income (expense), net increased $22 million, or 129.4%, from the prior year primarily due to an $8 million increase in wholesale operating fee revenue and a $9 million decrease in donations.

Income Taxes

Income taxes increased $6 million, or 0.8%, in 2014 compared to the prior year primarily due to higher pre-tax earnings and an increase in non-deductible book depreciation, partially offset by the recognition of tax benefits related to emission allowances and state apportionment, an increase in non-taxable AFUDC equity, and state income tax credits.

Income taxes increased $35 million, or 5.1%, in 2013 compared to the prior year primarily due to a decrease in state income tax credits, higher pre-tax earnings, and a decrease in non-taxable AFUDC equity, partially offset by a decrease in non-deductible book depreciation.

See "Allowance for Funds Used During Construction Equity" herein for additional information.

Effects of Inflation

The Company is subject to rate regulation that is generally based on the recovery of historical and projected costs. The effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. Any adverse effect of inflation on the Company's results of operations has not been substantial in recent years.

FUTURE EARNINGS POTENTIAL

General

The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located within the State of Georgia and to wholesale customers in the Southeast. Prices for electricity provided by the Company to retail customers are set by the Georgia PSC under cost-based regulatory principles. Prices for wholesale electricity sales, interconnecting transmission lines, and the exchange of electric power are regulated by the FERC. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Electric Utility Regulation" herein and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information about regulatory matters.

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the Company's ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently-incurred costs during a time of increasing costs and the completion and subsequent operation of ongoing construction projects, primarily Plant Vogtle Units 3 and 4. Future earnings in the near term will depend, in part, upon maintaining and growing sales which are subject to a number of factors. These factors include weather, competition, new energy contracts with other utilities, energy conservation practiced by customers, the use of alternative energy sources by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in the Company's service territory. Changes in regional and global economic conditions may impact sales for the Company, as the pace of the economic recovery remains uncertain. The timing and extent of the economic recovery will impact growth and may impact future earnings.

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Environmental Matters
Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified. The Company's Environmental Compliance Cost Recovery (ECCR) tariff allows for the recovery of capital and operations and maintenance costs related to environmental controls mandated by state and federal regulations. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively affect results of operations, cash flows, and financial condition. See Note 3 to the financial statements under "Environmental Matters" for additional information.
New Source Review Actions
As part of a nationwide enforcement initiative against the electric utility industry which began in 1999, the EPA brought civil enforcement actions in federal district court against the Company alleging violations of the New Source Review provisions of the Clean Air Act at certain coal-fired electric generating units, including a unit co-owned by Gulf Power. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. See Note 3 to the financial statements under "Environmental Matters – New Source Review Actions" for additional information. The ultimate outcome of these matters cannot be determined at this time.
Environmental Statutes and Regulations
General
The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; the Endangered Species Act; and related federal and state regulations. Compliance with these environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. Through 2014, the Company had invested approximately $4.7 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $0.4 billion, $0.3 billion, and $0.2 billion for 2014, 2013, and 2012, respectively. The Company expects that capital expenditures to comply with environmental statutes and regulations will total approximately $0.8 billion from 2015 through 2017, with annual totals of approximately $0.3 billion, $0.2 billion, and $0.2 billion for 2015, 2016, and 2017, respectively. These estimated expenditures do not include any potential compliance costs that may arise from the EPA's proposed rules that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. See "Global Climate Issues" for additional information.
The Company's ultimate environmental compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital expenditures will be affected by the final requirements of new or revised environmental regulations and regulations relating to global climate change that are promulgated, including the proposed environmental regulations described below; the outcome of any legal challenges to the environmental rules; the cost, availability, and existing inventory of emissions allowances; and the Company's fuel mix. Compliance costs may arise from existing unit retirements, installation of additional environmental controls, upgrades to the transmission system, closure and monitoring of CCR facilities, and adding or changing fuel sources for certain existing units. The ultimate outcome of these matters cannot be determined at this time. See "Retail Regulatory Matters – Integrated Resource Plans" herein for additional information on planned unit retirements and fuel conversions.

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

Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Company. Since 1990, the Company has spent approximately $4.3 billion in reducing and monitoring emissions pursuant to the Clean Air

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Act. Additional controls are currently planned or under consideration to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements.

In 2012, the EPA finalized the Mercury and Air Toxics Standards (MATS) rule, which imposes stringent emissions limits for acid gases, mercury, and particulate matter on coal- and oil-fired electric utility steam generating units. Compliance for existing sources is required by April 16, 2015 up to April 16, 2016 for affected units for which extensions have been granted. On November 25, 2014, the U.S. Supreme Court granted a petition for review of the final MATS rule.

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 2012, the EPA published its final determination of nonattainment areas based on the 2008 eight-hour ozone NAAQS. The only area within the Company's service territory designated as an ozone nonattainment area is a 15-county area within metropolitan Atlanta. On December 17, 2014, the EPA published a proposed rule to further reduce the current eight-hour ozone standard. The EPA is required by federal court order to complete this rulemaking by October 1, 2015. Finalization of a lower eight-hour ozone standard could result in the designation of new ozone nonattainment areas within the Company's service territory.

The EPA regulates fine particulate matter concentrations on an annual and 24-hour average basis. All areas within the Company's service territory have achieved attainment with the 1997 and 2006 particulate matter NAAQS and, with the exception of the Atlanta area, the EPA has officially redesignated former nonattainment areas within the service territory as attainment for these standards. A redesignation request for the Atlanta area is pending with the EPA. In 2012, the EPA issued a final rule that increases the stringency of the annual fine particulate matter standard. The EPA promulgated final designations for the 2012 annual standard on December 18, 2014, and no new nonattainment areas were designated within the Company's service territory. The EPA has, however, deferred designation decisions for certain areas in Georgia, so future nonattainment designations in these areas are possible.

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

The Company's service territory is subject to the requirements of the Cross State Air Pollution Rule (CSAPR). CSAPR is an emissions trading program that limits SO_2 and nitrogen oxide emissions from power plants in 28 states in two phases, with Phase I beginning in 2015 and Phase II beginning in 2017. In 2012, the U.S. Court of Appeals for the District of Columbia Circuit vacated CSAPR in its entirety, but on April 29, 2014, the U.S. Supreme Court overturned that decision and remanded the case back to the U.S. Court of Appeals for the District of Columbia Circuit for further proceedings. The U.S. Court of Appeals for the District of Columbia Circuit granted the EPA's motion to lift the stay of the rule, and the first phase of CSAPR took effect on January 1, 2015.

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, including fossil fuel-fired generating facilities, built between 1962 and 1977 and any additional emissions reductions necessary for each designated area to achieve reasonable progress toward the natural visibility conditions goal by 2018 and for each 10-year period thereafter.

In 2012, the EPA published proposed revisions to the New Source Performance Standard (NSPS) for Stationary Combustion Turbines (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.

In February 2013, the EPA proposed a rule that would require certain states to revise the provisions of their State Implementation Plans (SIPs) relating to the regulation of excess emissions at industrial facilities, including fossil fuel-fired generating facilities, during periods of startup, shut-down, or malfunction (SSM). The EPA proposed to supplement the 2013 proposed rule on September 17, 2014, making it more stringent. The EPA has entered into a settlement agreement requiring it to finalize the proposed rule by May 22, 2015. The proposed rule would require states subject to the rule (including Georgia, Alabama, and Florida) to revise their SSM provisions within 18 months after issuance of the final rule.

The Company has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the current and proposed environmental requirements discussed above. As part of this strategy, the Company has developed a compliance plan for the MATS rule which includes reliance on existing emission control technologies,

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the construction of baghouses to provide an additional level of control on the emissions of mercury and particulates from certain generating units, the use of additives or other injection technology, the use of additional natural gas capability, and unit retirements. Additionally, certain transmission system upgrades are required. The impacts of the eight-hour ozone, fine particulate matter and SO_2 NAAQS, CSAPR, CAVR, the MATS rule, the NSPS for CTs, and the SSM rule on the Company cannot be determined at this time and will depend on the specific provisions of the proposed and final rules, the resolution of pending and future legal challenges, and/or the development and implementation of rules at the state level. These regulations could result in significant additional 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.

In addition to the federal air quality laws described above, the Company is also subject to the requirements of the 2007 State of Georgia Multi-Pollutant Rule. The Multi-Pollutant Rule, as amended, is designed to reduce emissions of mercury, SO_2, and nitrogen oxide 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, 2014, the Company had installed the required controls on 14 of its coal-fired generating units with two additional projects to be completed before the unit-specific installation deadlines.

Water Quality

The EPA's final rule establishing standards for reducing effects on fish and other aquatic life caused by new and existing cooling water intake structures at existing power plants and manufacturing facilities became effective on October 14, 2014. The effect of this final rule will depend on the results of additional studies and implementation of the rule by regulators based on site-specific factors. The ultimate impact of this rule will also depend on the outcome of ongoing legal challenges and cannot be determined at this time.

In June 2013, the EPA published a proposed rule which requested comments on a range of potential regulatory options for addressing revised technology-based limits for certain wastestreams from steam electric power plants and best management practices for CCR surface impoundments. The EPA has entered into a consent decree requiring it to finalize revisions to the steam electric effluent guidelines by September 30, 2015. The ultimate impact of the rule will also depend on the specific technology requirements of the final rule and the outcome of any legal challenges and cannot be determined at this time.

On April 21, 2014, the EPA and the U.S. Army Corps of Engineers jointly published a proposed rule to revise the regulatory definition of waters of the U.S. for all Clean Water Act (CWA) programs, which would significantly expand the scope of federal jurisdiction under the CWA. In addition, the rule as proposed could have significant impacts on economic development projects which could affect customer demand growth. The ultimate impact of the proposed rule will depend on the specific requirements of the final rule and the outcome of any legal challenges and cannot be determined at this time. If finalized as proposed, this rule could significantly increase permitting and regulatory requirements and costs associated with the siting of new facilities and the installation, expansion, and maintenance of transmission and distribution lines.

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

Coal Combustion Residuals

The Company currently manages CCR at onsite units consisting of landfills and surface impoundments (CCR Units) at 11 electric generating plants. In addition to on-site storage, the Company also sells a portion of its CCR to third parties for beneficial reuse. Individual states regulate CCR and the State of Georgia has its own regulatory requirements. The Company has an inspection program in place to assist in maintaining the integrity of its coal ash surface impoundments.

On December 19, 2014, the EPA issued the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule), but has not yet published it in the Federal Register. The CCR Rule will regulate the disposal of CCR, including coal ash and gypsum, as non-hazardous solid waste in CCR Units at active generating power plants. The CCR Rule does not mandate closure of CCR Units, but includes minimum criteria for active and inactive surface impoundments containing CCR and liquids, lateral expansions of existing units, and active landfills. Failure to meet the minimum criteria can result in the mandated closure of a CCR Unit. Although the EPA does not require individual states to adopt the final criteria, states have the option to incorporate the federal criteria into their state solid waste management plans in order to regulate CCR in a manner consistent with federal standards. The EPA's final rule continues to exclude the beneficial use of CCR from regulation.

The ultimate impact of the CCR Rule cannot be determined at this time and will depend on the Company's ongoing review of the CCR Rule, the results of initial and ongoing minimum criteria assessments, and the outcome of legal challenges. The cost and

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timing of potential ash pond closure and ongoing monitoring activities that may be required in connection with the CCR Rule is also uncertain; however, the Company has developed a preliminary nominal dollar estimate of costs associated with closure and groundwater monitoring of ash ponds in place of approximately $390 million and ongoing post-closure care of approximately $62 million. The Company has previously recorded asset retirement obligations (ARO) associated with ash ponds of $500 million, or $458 million on a nominal dollar basis, based on existing state requirements. During 2015, the Company will record AROs for any incremental estimated closure costs resulting from acceleration in the timing of any currently planned closures and for differences between existing state requirements and the requirements of the CCR Rule. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates.

Environmental Remediation

The Company must comply with other environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company may also incur substantial costs to clean up properties. The Company conducts studies to determine the extent of any required cleanup and has recognized in its financial statements the costs to clean up known impacted sites. Amounts for cleanup and ongoing monitoring costs were not material for any year presented. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Notes 1 and 3 to the financial statements under "Environmental Remediation Recovery" and "Environmental Matters – Environmental Remediation," respectively, for additional information.

Global Climate Issues

In 2014, the EPA published three sets of proposed standards that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. On January 8, 2014, the EPA published proposed standards for new units, and, on June 18, 2014, the EPA published proposed standards governing existing units, known as the Clean Power Plan, and separate standards governing CO_2 emissions from modified and reconstructed units. The EPA's proposed Clean Power Plan establishes guidelines for states to develop plans to address CO_2 emissions from existing fossil fuel-fired electric generating units. The EPA's proposed guidelines establish state-specific interim and final CO_2 emission rate goals to be achieved between 2020 and 2029 and in 2030 and thereafter. The proposed guidelines and standards could result in operational restrictions and material compliance costs, including capital expenditures, which could affect future unit retirement and replacement decisions. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates.

The Southern Company system filed comments on the EPA's proposed Clean Power Plan on December 1, 2014. These comments addressed legal and technical issues in addition to providing a preliminary estimated cost of complying with the proposed guidelines utilizing one of the EPA's compliance scenarios. Costs associated with this proposal could be significant to the utility industry and the Southern Company system. However, the ultimate financial and operational impact of the proposed Clean Power Plan on the Southern Company system cannot be determined at this time and will depend upon numerous known and unknown factors. Some of the unknown factors include: the structure, timing, and content of the EPA's final guidelines; individual state implementation of these guidelines, including the potential that state plans impose different standards; additional rulemaking activities in response to legal challenges and related court decisions; the impact of future changes in generation and emissions-related technology and costs; the impact of future decisions regarding unit retirement and replacement, including the type and amount of any such replacement capacity; and the time periods over which compliance will be required.

Over the past several years, the U.S. Congress has also 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.

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 Company's 2013 greenhouse gas emissions were approximately 33 million metric tons of CO_2 equivalent. The preliminary estimate of the Company's 2014 greenhouse gas emissions on the same basis is approximately 38 million metric tons of CO_2 equivalent. The level of greenhouse gas emissions from year to year will depend on the level of generation, the mix of fuel sources, and other factors.

Retail Regulatory Matters

The Company's revenues from regulated retail operations are collected through various rate mechanisms subject to the oversight of the Georgia PSC. The Company currently recovers its costs from the regulated retail business through the 2013 ARP, which includes traditional base tariff rates, Demand-Side Management (DSM) tariffs, ECCR tariffs, and Municipal Franchise Fee (MFF) tariffs. In addition, financing costs related to the construction of Plant Vogtle Units 3 and 4 are being collected through the NCCR

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tariff and fuel costs are collected through separate fuel cost recovery tariffs. See Note 3 to the financial statements under "Retail Regulatory Matters" for additional information.

Rate Plans

In December 2013, the Georgia PSC voted to approve the 2013 ARP. The 2013 ARP reflects the settlement agreement among the Company, the Georgia PSC's Public Interest Advocacy Staff, and 11 of the 13 intervenors, which was filed with the Georgia PSC in November 2013.

On January 1, 2014, in accordance with the 2013 ARP, the Company increased its tariffs as follows: (1) traditional base tariff rates by approximately $80 million; (2) ECCR tariff by approximately $25 million; (3) DSM tariffs by approximately $1 million; and (4) MFF tariff by approximately $4 million, for a total increase in base revenues of approximately $110 million.

On February 19, 2015, in accordance with the 2013 ARP, the Georgia PSC approved adjustments to traditional base, ECCR, DSM, and MFF tariffs effective January 1, 2015 as follows:

- Traditional base tariffs by approximately $107 million to cover additional capacity costs;
- ECCR tariff by approximately $23 million;
- DSM tariffs by approximately $3 million; and
- MFF tariff by approximately $3 million to reflect the adjustments above.

The sum of these adjustments resulted in a base revenue increase of approximately $136 million in 2015.

The 2016 base rate increase, which was approved in the 2013 ARP, will be determined through a compliance filing expected to be filed in late 2015, and will be subject to review by the Georgia PSC.

Under the 2013 ARP, the Company'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 the Company. There will be no recovery of any earnings shortfall below 10.00% on an actual basis. However, if at any time during the term of the 2013 ARP, the Company projects that its retail earnings will be below 10.00% for any calendar year, it may petition the Georgia PSC for implementation of the Interim Cost Recovery (ICR) tariff that would be used to adjust the Company's earnings back to a 10.00% retail ROE. The Georgia PSC would have 90 days to rule on the Company's request. The ICR tariff will expire at the earlier of January 1, 2017 or the end of the calendar year in which the ICR tariff becomes effective. In lieu of requesting implementation of an ICR tariff, or if the Georgia PSC chooses not to implement the ICR tariff, the Company may file a full rate case. In 2014, the Company's retail ROE exceeded 12.00%, and the Company expects to refund to retail customers approximately $13 million in 2015, subject to review and approval by the Georgia PSC.

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

Renewables Development

On May 20, 2014, the Georgia PSC approved the Company's application for the certification of two PPAs executed in April 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.

On December 16, 2014, the Georgia PSC approved and certified ten PPAs that were executed in October 2014. These PPAs provide for the purchase of energy from 515 MWs of solar capacity as part of the Georgia Power Advanced Solar Initiative program, of which approximately 99 MWs is expected to be purchased from solar facilities owned by Southern Power. These PPAs are expected to commence in December 2015 and 2016 and have terms ranging from 20 to 30 years.

On October 23, 2014, the Georgia PSC approved the Company's request to build, own, and operate three 30-MW solar generation facilities at three U.S. Army bases by the end of 2016. In addition, on December 16, 2014, the Georgia PSC approved the Company's request to build, own, and operate a 30-MW solar generation facility at Kings Bay Naval facility by the end of 2016.

Integrated Resource Plans

See "Environmental Matters – Environmental Statutes and Regulations – Air Quality," "– Water Quality," "– Coal Combustion Residuals," and "– Global Climate Issues," and "Rate Plans" herein for additional information regarding proposed and final EPA rules and regulations, including the MATS rule for coal- and oil-fired electric utility steam generating units, revisions to effluent limitations guidelines for steam electric power plants, and additional regulations of CCR and CO_2; the State of Georgia's Multi-

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Pollutant Rule; and the Company's analysis of the potential costs and benefits of installing the required controls on its fossil generating units in light of these regulations.

In July 2013, the Georgia PSC approved the Company's latest triennial Integrated Resource Plan (2013 IRP) including the Company's request to decertify 16 coal- and oil-fired units totaling 2,093 MWs. Several factors, including the cost to comply with existing and future environmental regulations, recent and forecasted economic conditions, and lower natural gas prices, contributed to the decision to close these units.

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 (250 MWs) was extended from December 31, 2013 as specified in the final order in the 2011 Integrated Resource Plan Update (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) were 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 in September 2013 to allow for necessary transmission system reliability improvements. In July 2013, the Georgia PSC approved the switch to natural gas as the primary fuel for Plant Yates Units 6 and 7. In September 2013, Plant Branch Unit 2 (319 MWs) was retired as approved by the Georgia PSC in the 2011 IRP Update in order to comply with the State of Georgia's Multi-Pollutant Rule.

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 the Company's next base rate case, which the Company expects to file in 2016 (2016 Rate Case). In the 2013 IRP, the Georgia PSC also deferred decisions regarding the recovery of any fuel related costs that could be incurred in connection with the retirement units to be addressed in future fuel cases.

On July 1, 2014, the Georgia PSC approved the Company's request to cancel the proposed biomass fuel conversion of Plant Mitchell Unit 3 (155 MWs) because it would not be cost effective for customers. The Company expects to request decertification of Plant Mitchell Unit 3 in connection with the triennial Integrated Resource Plan to be filed in 2016. The Company plans to continue to operate the unit as needed until the MATS rule becomes effective in April 2015.

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

Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Georgia PSC. The Company continues to be allowed to adjust its fuel cost recovery rates prior to the next fuel case if the under or over recovered fuel balance exceeds $200 million. On January 20, 2015, the Georgia PSC approved the deferral of the Company's next fuel case filing until at least June 30, 2015.

Nuclear Construction

In 2008, the Company, acting for itself and as agent for Oglethorpe Power Corporation (OPC), the Municipal Electric Authority of Georgia (MEAG Power), and the City of Dalton, Georgia (Dalton), acting by and through its Board of Water, Light, and Sinking Fund Commissioners (collectively, Vogtle Owners), entered into an agreement with a consortium consisting of Westinghouse Electric Company LLC (Westinghouse) and Stone & Webster, Inc., a subsidiary of The Shaw Group Inc., which was acquired by Chicago Bridge & Iron Company N.V. (CB&I) (collectively, Contractor), pursuant to which the Contractor agreed to design, engineer, procure, construct, and test two AP1000 nuclear units (with electric generating capacity of approximately 1,100 MWs each) and related facilities at Plant Vogtle (Vogtle 3 and 4 Agreement). Under the terms of the Vogtle 3 and 4 Agreement, the Vogtle Owners agreed to pay a purchase price that is subject to certain price escalations and adjustments, including fixed escalation amounts and index-based adjustments, as well as adjustments for change orders, and performance bonuses for early completion and unit performance. The Vogtle 3 and 4 Agreement also provides for liquidated damages upon the Contractor's failure to fulfill the schedule and performance guarantees. The Contractor's liability to the Vogtle Owners for schedule and performance liquidated damages and warranty claims is subject to a cap. In addition, the Vogtle 3 and 4 Agreement provides for limited cost sharing by the Vogtle Owners for Contractor costs under certain conditions (which have not occurred), with maximum additional capital costs under this provision attributable to the Company (based on the Company's ownership interest) of approximately $114 million. Each Vogtle Owner is severally (and not jointly) liable for its proportionate share, based

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on its ownership interest, of all amounts owed to the Contractor under the Vogtle 3 and 4 Agreement. The Company's proportionate share is 45.7%.

Certain payment obligations of Westinghouse and Stone & Webster, Inc. under the Vogtle 3 and 4 Agreement are guaranteed by Toshiba Corporation and CB&I's The Shaw Group Inc., respectively. In the event of certain credit rating downgrades of any Vogtle Owner, such Vogtle Owner will be required to provide a letter of credit or other credit enhancement. The Vogtle Owners may terminate the Vogtle 3 and 4 Agreement at any time for their convenience, provided that the Vogtle Owners will be required to pay certain termination costs. The Contractor may terminate the Vogtle 3 and 4 Agreement under certain circumstances, including certain Vogtle Owner suspension or delays of work, action by a governmental authority to permanently stop work, certain breaches of the Vogtle 3 and 4 Agreement by the Vogtle Owners, Vogtle Owner insolvency, and certain other events.

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

In 2009, the Georgia PSC approved inclusion of the Plant Vogtle Units 3 and 4 related CWIP accounts in rate base, and the State of Georgia enacted the Georgia Nuclear Energy Financing Act, which allows the Company to recover financing costs for nuclear construction projects certified by the Georgia PSC. Financing costs are recovered on all applicable certified costs through annual adjustments to the NCCR tariff by including the related CWIP accounts in rate base during the construction period. The Georgia PSC approved increases to the NCCR tariff of approximately $223 million, $35 million, $50 million, and $60 million, effective January 1, 2011, 2012, 2013, and 2014, respectively. On December 16, 2014, the Georgia PSC approved an increase to the NCCR tariff of approximately $27 million effective January 1, 2015.

In 2012, the Vogtle 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 Vogtle Owners are responsible for these costs under the terms of the Vogtle 3 and 4 Agreement. Also in 2012, the Company and the other Vogtle Owners filed suit against the Contractor in the U.S. District Court for the Southern District of Georgia seeking a declaratory judgment that the Vogtle Owners are not responsible for these costs. In 2012, the Contractor also filed suit against the Company and the other Vogtle Owners in the U.S. District Court for the District of Columbia alleging the Vogtle Owners are responsible for these costs. In August 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 in September 2013. The portion of additional costs claimed by the Contractor in its initial complaint that would be attributable to the Company (based on the Company's ownership interest) is approximately $425 million (in 2008 dollars). The Contractor also asserted it is entitled to extensions of the guaranteed substantial completion dates of April 2016 and April 2017 for Plant Vogtle Units 3 and 4, respectively. On May 22, 2014, the Contractor filed an amended counterclaim to the suit pending in the U.S. District Court for the Southern District of Georgia alleging that (i) the design changes to the DCD imposed by the NRC delayed module production and the impacts to the Contractor are recoverable by the Contractor under the Vogtle 3 and 4 Agreement and (ii) the changes to the basemat rebar design required by the NRC caused additional costs and delays recoverable by the Contractor under the Vogtle 3 and 4 Agreement. The Contractor did not specify in its amended counterclaim the amounts relating to these new allegations; however, the Contractor has subsequently asserted related minimum damages (based on the Company's ownership interest) of $113 million. The Contractor may from time to time continue to assert that it is entitled to additional payments with respect to these allegations, any of which could be substantial. The Company has not agreed to the proposed cost or to any changes to the guaranteed substantial

completion dates or that the Vogtle Owners have any responsibility for costs related to these issues. Litigation is ongoing and the Company intends to vigorously defend the positions of the Vogtle Owners. The Company also expects negotiations with the Contractor to continue with respect to cost and schedule during which negotiations the parties may reach a mutually acceptable compromise of their positions.
The Company is required to file semi-annual Vogtle Construction Monitoring (VCM) reports with the Georgia PSC by February 28 and August 31 each year. If the projected certified construction capital costs to be borne by the Company increase by 5% or the projected in-service dates are significantly extended, the Company is required to seek an amendment to the Plant Vogtle Units 3 and 4 certificate from the Georgia PSC. The Company's eighth VCM report filed in February 2013 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.
In September 2013, the Georgia PSC approved a stipulation (2013 Stipulation) entered into by the Company and the Georgia PSC staff to waive the requirement to amend the Plant Vogtle Units 3 and 4 certificate, until the completion of Plant Vogtle Unit 3, or

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earlier if deemed appropriate by the Georgia PSC and the Company. In accordance with the Georgia Integrated Resource Planning Act, any costs incurred by the Company in excess of the certified amount will be included in rate base, provided the Company shows the costs to be reasonable and prudent. In addition, financing costs on any construction-related costs in excess of the certified amount likely would be subject to recovery through AFUDC instead of the NCCR tariff.

The Georgia PSC has approved eleven VCM reports covering the periods through June 30, 2014, including construction capital costs incurred, which through that date totaled $2.8 billion.

On January 29, 2015, the Company announced that it was notified by the Contractor of the Contractor's revised forecast for completion of Plant Vogtle Units 3 and 4, which would incrementally delay the previously disclosed estimated in-service dates by 18 months (from the fourth quarter of 2017 to the second quarter of 2019 for Unit 3 and from the fourth quarter of 2018 to the second quarter of 2020 for Unit 4). The Company has not agreed to any changes to the guaranteed substantial completion dates of April 2016 and April 2017 for Plant Vogtle Units 3 and 4, respectively. The Company does not believe that the Contractor's revised forecast reflects all efforts that may be possible to mitigate the Contractor's delay.

In addition, the Company believes that, pursuant to the Vogtle 3 and 4 Agreement, the Contractor is responsible for the Contractor's costs related to the Contractor's delay (including any related construction and mitigation costs, which could be material) and that the Vogtle Owners are entitled to recover liquidated damages for the Contractor's delay beyond the guaranteed substantial completion dates of April 2016 and April 2017 for Plant Vogtle Units 3 and 4, respectively. Consistent with the Contractor's position in the pending litigation described above, the Company expects the Contractor to contest any claims for liquidated damages and to assert that the Vogtle Owners are responsible for additional costs related to the Contractor's delay.

On February 27, 2015, the Company filed its twelfth VCM report with the Georgia PSC covering the period from July 1 through December 31, 2014, which requests approval for an additional $0.2 billion of construction capital costs incurred during that period and reflects the Contractor's revised forecast for completion of Plant Vogtle Units 3 and 4 as well as additional estimated owner-related costs of approximately $10 million per month expected to result from the Contractor's proposed 18-month delay, including property taxes, oversight costs, compliance costs, and other operational readiness costs. No Contractor costs related to the Contractor's proposed 18-month delay are included in the twelfth VCM report. Additionally, while the Company has not agreed to any change to the guaranteed substantial completion dates, the twelfth VCM report includes a requested amendment to the Plant Vogtle Units 3 and 4 certificate to reflect the Contractor's revised forecast, to include the estimated owner's costs associated with the proposed 18-month Contractor delay, and to increase the estimated total in-service capital cost of Plant Vogtle Units 3 and 4 to $5.0 billion.

The Company will continue to incur financing costs of approximately $30 million per month until Plant Vogtle Units 3 and 4 are placed in service. The twelfth VCM report estimates total associated financing costs during the construction period to be approximately $2.5 billion.

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 Vogtle Owners or the Contractor or to both.

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

Plant Vogtle Units 3 and 4, which require the applicable unit to be placed in service before 2021.
Additional claims by the Contractor or the Company (on behalf of the Vogtle 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.

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Income Tax Matters
Bonus Depreciation
On December 19, 2014, the Tax Increase Prevention Act of 2014 (TIPA) was signed into law. The TIPA retroactively extended several tax credits through 2014 and extended 50% bonus depreciation for property placed in service in 2014 (and for certain long-term production-period projects to be placed in service in 2015). The extension of 50% bonus depreciation had a positive impact on the Company's cash flows and, combined with bonus depreciation allowed in 2014 under the American Taxpayer Relief Act of 2012, resulted in approximately $200 million of positive cash flows for the 2014 tax year. The estimated cash flow benefit of bonus depreciation related to TIPA is expected to be approximately $45 million to $50 million for the 2015 tax year.
Other Matters
The Company is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of business. The Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements, such as air quality and water standards, has occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by CO_2 and other emissions, CCR, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters.
The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements. See Note 3 to the financial statements for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.
ACCOUNTING POLICIES
Application of Critical Accounting Policies and Estimates
The Company prepares its financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on the Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has reviewed and discussed the following critical accounting policies and estimates with the Audit Committee of Southern Company's Board of Directors.
Electric Utility Regulation
The Company is subject to retail regulation by the Georgia PSC and wholesale regulation by the FERC. These regulatory agencies set the rates the Company is permitted to charge customers based on allowable costs. As a result, the Company applies accounting standards which require the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of the accounting standards has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the Company; therefore, the accounting estimates inherent in specific costs such as depreciation, AROs, and pension and postretirement benefits have less of a direct impact on the Company's results of operations and financial condition than they would on a non-regulated company.
As reflected in Note 1 to the financial statements, significant regulatory assets and liabilities have been recorded. Management reviews the ultimate recoverability of these regulatory assets and any requirement to refund these

regulatory liabilities based on applicable regulatory guidelines and GAAP. However, adverse legislative, judicial, or regulatory actions could materially impact the amounts of such regulatory assets and liabilities and could adversely impact the Company's financial statements.

Contingent Obligations

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

Pension and Other Postretirement Benefits

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

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

For purposes of its December 31, 2014 measurement date, the Company adopted new mortality tables for its pension plans and retiree life and medical plans, which reflect increased life expectancies in the U.S. The adoption of new mortality tables increased the projected benefit obligations for the Company's pension plans and other postretirement benefit plans by approximately $226 million and $46 million, respectively. The adoption of new mortality tables will increase net periodic costs related to the Company's pension plans and other postretirement benefit plans in 2015 by $30 million and $5 million, respectively.

A 25 basis point change in any significant assumption (discount rate, salaries, or long-term return on plan assets) would result in an $11 million or less change in total annual benefit expense and a $163 million or less change in projected obligations.

Recently Issued Accounting Standards

On May 28, 2014, the Financial Accounting Standards Board issued ASC 606, Revenue from Contracts with Customers. ASC 606 revises the accounting for revenue recognition and is effective for fiscal years beginning after December 15, 2016. The Company continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2014. The Company's cash requirements primarily consist of funding ongoing operations, common stock dividends, capital expenditures, and debt maturities. Capital expenditures and other investing activities include investments to meet projected long-term demand requirements, to comply with environmental regulations, and for restoration following major storms. Operating cash flows provide a substantial portion of the Company's cash needs. For the three-year period from 2015 through 2017, the Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. Projected capital expenditures in that period include investments to build new generation facilities, including Plant Vogtle Units 3 and 4, to maintain existing generation facilities, to add environmental equipment for existing generating units, to add or change fuel sources for certain existing units, and to expand and improve transmission and distribution facilities. The Company plans to finance future cash needs in excess of its operating cash flows primarily through debt issuances and capital contributions from Southern Company, as well as by accessing borrowings from financial institutions and borrowings through the FFB. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements to meet future capital and liquidity needs. See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

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The Company's investments in the qualified pension plan and the nuclear decommissioning trust funds increased in value as of December 31, 2014 as compared to December 31, 2013. On December 18, 2014, the Company voluntarily contributed $150 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2015. The Company funded approximately $2 million to its nuclear decommissioning trust funds in 2014. See "Contractual Obligations" herein and Notes 1 and 2 to the financial statements under "Nuclear Decommissioning" and "Pension Plans," respectively, for additional information.

Net cash provided from operating activities totaled $2.4 billion in 2014, a decrease of $403 million from 2013, primarily due to fuel cost recovery and storm restoration costs, partially offset by higher retail operating revenues and lower fuel inventory additions. Net cash provided from operating activities totaled $2.8 billion in 2013, an increase of $471 million from 2012, primarily due to higher retail operating revenues, lower fuel inventory additions, and settlement of affiliated payables related to pension funding in 2012, partially offset by fuel cost recovery.

Net cash used for investing activities totaled $2.2 billion, $1.9 billion, and $2.0 billion in 2014, 2013, and 2012, respectively, due to gross property additions primarily related to installation of equipment to comply with environmental standards; construction of generation, transmission, and distribution facilities; and purchase of nuclear fuel. The majority of funds needed for gross property additions for the last several years has been provided from operating activities, capital contributions from Southern Company, and the issuance of debt. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Nuclear Construction" herein for additional information.

Net cash used for financing activities totaled $163 million, $891 million, and $290 million for 2014, 2013, and 2012, respectively. The decrease in cash used in 2014 compared to 2013 was primarily due to borrowings from the FFB for construction of Plant Vogtle Units 3 and 4, partially offset by FFB loan issuance costs and a reduction in short-term debt. The increase in cash used in 2013 compared to 2012 was primarily due to lower net issuances of long-term debt in 2013, partially offset by an increase in net short-term borrowings. See "Financing Activities" herein for additional information. Fluctuations in cash flow from financing activities vary from year to year based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes in 2014 included an increase of $1.2 billion in total property, plant, and equipment due to gross property additions described above, an increase in other regulatory assets, deferred of $640 million, a decrease of $303 million in fossil fuel stock due to an increase in fuel generation, and an increase of $361 million in employee benefit obligations primarily as a result of changes in the actuarial assumptions. See Note 2 to the financial statements for additional information.

The Company's ratio of common equity to total capitalization, including short-term debt, was 50.4% in 2014 and 49.1% in 2013. See Note 6 to the financial statements for additional information.

Sources of Capital

Except as described below with respect to the DOE loan guarantees, the Company plans to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily from operating cash flows, short-term debt, security issuances, term loans, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon regulatory approvals, prevailing market conditions, and other factors.

On February 20, 2014, the Company and the DOE entered into a loan guarantee agreement (Loan Guarantee Agreement), pursuant to which the DOE agreed to guarantee borrowings to be made by the Company under a multi-advance credit facility (FFB Credit Facility) among the Company, the DOE, and the FFB. The Company is obligated to reimburse the DOE for any payments the DOE is required to make to the FFB under the guarantee. The Company's reimbursement obligations to the DOE are full recourse and also are secured by a first priority lien on (i) the Company's 45.7% ownership interest in Plant Vogtle Units 3 and 4 (primarily the units under construction, the related real property, and any nuclear fuel loaded in the reactor core) and (ii) the Company's rights and obligations under the principal contracts relating to Plant Vogtle Units 3 and 4. Under the FFB Credit Facility, the Company may make term loan borrowings through the FFB. Proceeds of borrowings made under the FFB Credit Facility will be used to reimburse the Company for a portion of certain costs of construction relating to Plant Vogtle Units 3 and 4 that are eligible for financing under the Loan Guarantee Agreement (Eligible Project Costs). Aggregate borrowings under the FFB Credit Facility may not exceed the lesser of (i) 70% of Eligible Project Costs or (ii) approximately $3.46 billion. See Note 6 to the financial statements under "DOE Loan Guarantee Borrowings" for additional information regarding the Loan Guarantee Agreement and Note 3 to the financial statements under "Retail Regulatory Matters – Nuclear Construction" for additional information regarding Plant Vogtle Units 3 and 4.

Eligible Project Costs incurred through December 31, 2014 would allow for borrowings of up to $2.1 billion under the FFB Credit Facility. Through December 31, 2014, the Company had borrowed $1.2 billion under the FFB Credit Facility, leaving $0.9 billion of currently available borrowing ability.

The issuance of long-term securities by the Company is subject to the approval of the Georgia PSC. In addition, the issuance of short-term debt securities by the Company is subject to regulatory approval by the FERC. Additionally, with respect to the public offering of securities, the Company files registration statements with the SEC under the Securities Act of 1933, as amended. The amounts of securities authorized by the Georgia PSC and the FERC are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

The Company obtains financing separately without credit support from any affiliate. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of the Company are not commingled with funds of any other company in the Southern Company system.

As of December 31, 2014, the Company's current liabilities exceeded current assets by $1.0 billion primarily due to long-term debt that is due in one year. The Company intends to utilize equity contributions from Southern Company and cash from operations, as well as commercial paper, lines of credit, bank notes, and securities issuances, as market conditions permit, to fund the Company's short-term capital needs. In 2015, the Company also expects to utilize borrowings through the FFB as the primary source of borrowed funds. The Company has substantial cash flow from operating activities and access to the capital markets and financial institutions to meet short-term liquidity needs.

At December 31, 2014, the Company had approximately $24 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2014 were as follows:

Expires[(a)]			
2016	2018	Total	Unused
(in millions)			
$150	$1,600	$1,750	$1,736

(a) No credit arrangements expire in 2015 or 2017.

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

A portion of the unused credit with banks is allocated to provide liquidity support to the Company's variable rate pollution control revenue bonds and commercial paper program. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2014 was approximately $865 million. In addition, at December 31, 2014, the Company had $118 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months. As of December 31, 2014, $98 million of certain pollution control revenue bonds of the Company were reclassified to securities due within one year in anticipation of their redemption in connection with unit retirement decisions.

The Company's credit arrangements contain covenants that limit debt levels and contain cross default provisions to other indebtedness (including guarantee obligations) of the Company. Such cross default provisions to other indebtedness would trigger an event of default if the Company defaulted on indebtedness or guarantee obligations over a specified threshold. The Company is currently in compliance with all such covenants. None of the bank credit arrangements contain material adverse change clauses at the time of borrowings. Subject to applicable market conditions, the Company expects to renew its credit arrangements, as needed, prior to expiration.

The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of the Company and the other traditional operating companies. Proceeds from such issuances for the benefit of the Company are loaned directly to the Company. The obligations of each company under these arrangements are several and there is no cross-affiliate credit support.

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Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period			Short-term Debt During the Period (a)			
	Amount Outstanding	Weighted Average Interest Rate		Average Outstanding	Weighted Average Interest Rate		Maximum Amount Outstanding
	(in millions)			(in millions)			(in millions)
December 31, 2014:							
Commercial paper	$156	0.3	%	$280	0.2	%	$703
Short-term bank debt	—	—	%	56	0.9	%	400
Total	$156	0.3	%	$336	0.3	%	
December 31, 2013:							
Commercial paper	$647	0.2	%	$166	0.2	%	$702
Short-term bank debt	400	0.9	%	96	0.9	%	400
Total	$1,047	0.5	%	$262	0.5	%	
December 31, 2012:							
Commercial paper	$—	—	%	$78	0.2	%	$517
Short-term bank debt	—	—	%	116	1.2	%	300
Total	$—	—	%	$194	0.8	%	

(a) Average and maximum amounts are based upon daily balances during the twelve-month periods ended December 31, 2014, 2013, and 2012.

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

Financing Activities

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

Pollution Control Revenue Bonds

In June 2014, the Company redeemed $17 million aggregate principal amount of Development Authority of Bartow County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Bowen Project), Second Series 1998 and $19.5 million aggregate principal amount of Development Authority of Appling County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Hatch Project), Second Series 2001.

In July 2014, the Company reoffered to the public $40 million aggregate principal amount of Development Authority of Monroe County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Scherer Project), First Series 2009, which had been previously purchased and held by the Company since 2010.

DOE Loan Guarantee Borrowings

On February 20, 2014, the Company made initial borrowings under the FFB Credit Facility in an aggregate principal amount of $1.0 billion and on December 11, 2014, the Company made additional borrowings under the FFB Credit Facility in an aggregate principal amount of $200 million. The interest rate applicable to $500 million of the initial advance under the FFB Credit Facility is 3.860% for an interest period that extends to 2044 and the interest rate applicable to the remaining $500 million is 3.488% for an interest period that extends to 2029 and is expected to be reset from time to time thereafter through 2044. The interest rate applicable to the $200 million advance in December 2014 is 3.002% for an interest period that extends to 2044. The final maturity date for all advances under the FFB Credit Facility is February 20, 2044. The proceeds of the borrowings in 2014 under the FFB Credit Facility were used to reimburse the Company for Eligible Project Costs relating to the construction of Plant Vogtle Units 3 and 4. In connection with its entry into the agreements with the DOE and the FFB, the Company incurred issuance costs of approximately $66 million, which are being amortized over the life of the borrowings under the FFB Credit Facility.

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Under the Loan Guarantee Agreement, the Company 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 the Company or Southern Nuclear 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.

Other

In February 2014, the Company repaid three four-month floating rate bank loans in an aggregate principal amount of $400 million. At December 31, 2014, the Company had no bank term loans outstanding.

In October 2014, the Company entered into interest rate swaps to hedge exposure to interest rate changes related to existing debt. The notional amount of the swaps totaled $900 million.

In November and December 2014, the Company entered into forward-starting interest rate swaps to hedge exposure to interest rate changes related to anticipated borrowings under the FFB Credit Facility in 2015. The notional amount of the swaps totaled $700 million.

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade.

There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel purchases, fuel transportation and storage, energy price risk management, interest rate derivatives, and construction of new generation. The maximum potential collateral requirements under these contracts at December 31, 2014 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB- and/or Baa3	$85
Below BBB- and/or Baa3	1,332

Included in these amounts are certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact the Company's ability to access capital markets, particularly the short-term debt market and the variable rate pollution control revenue bond market.

Market Price Risk

Due to cost-based rate regulation and other various cost recovery mechanisms, the Company continues to have limited exposure to market volatility in interest rates, commodity fuel prices, and prices of electricity. To manage the volatility attributable to these exposures, the Company nets the exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis.

To mitigate future exposure to changes in interest rates, the Company may enter into derivatives designated as hedges. The weighted average interest rate on $1.3 billion of long-term variable interest rate exposure at January 1, 2015 was

1.24%. If the Company sustained a 100 basis point change in interest rates for all long-term variable interest rate exposure, the change would affect annualized interest expense by approximately $13 million at January 1, 2015. See Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements for additional information.

To mitigate residual risks relative to movements in electricity prices, the Company enters into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, financial hedge contracts for

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natural gas purchases. The Company continues to manage a fuel-hedging program implemented per the guidelines of the Georgia PSC. The Company had no material change in market risk exposure for the year ended December 31, 2014 when compared to the December 31, 2013 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:

	2014 Changes	2013 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	$(16)	$(34)
Contracts realized or settled:		
Swaps realized or settled	2	9
Options realized or settled	8	20
Current period changes[(a)]:		
Swaps	(1)	1
Options	(13)	(12)
Contracts outstanding at the end of the period, assets (liabilities), net	$(20)	$(16)

(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:

	2014	2013
	mmBtu Volume	
	(in millions)	
Commodity – Natural gas swaps	4	7
Commodity – Natural gas options	42	52
Total hedge volume	46	59

The weighted average swap contract cost above market prices was approximately $0.68 per mmBtu as of December 31, 2014 and $0.50 per mmBtu as of December 31, 2013. The change in option fair value is primarily attributable to the volatility of the market and the underlying change in the natural gas price. All natural gas hedge gains and losses are recovered through the Company's fuel cost recovery mechanism.

At December 31, 2014 and 2013, substantially all of the Company's energy-related derivative contracts were designated as regulatory hedges and were related to the Company's fuel-hedging program, which have a 24-month time horizon. Hedging gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the fuel cost recovery mechanism. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred and were not material for any year presented.

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The Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. See Note 10 to the financial statements for further discussion of fair value measurements. The maturities of the energy-related derivative contracts, which are all Level 2 of the fair value hierarchy, at December 31, 2014 were as follows:

	Fair Value Measurements December 31, 2014		
	Total Fair Value	Maturity Year 1	Years 2&3
	(in millions)		
Level 1	$—	$—	$—
Level 2	(20)	(16)	(4)
Level 3	—	—	—
Fair value of contracts outstanding at end of period	$(20)	$(16)	$(4)

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

Capital Requirements and Contractual Obligations

The construction program of the Company is currently estimated to be $2.4 billion for 2015, $2.4 billion for 2016, and $2.1 billion for 2017. Capital expenditures to comply with environmental statutes and regulations included in these estimated amounts are $0.3 billion, $0.2 billion, and $0.2 billion for 2015, 2016, and 2017, respectively. These amounts include capital expenditures related to contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements. These estimated expenditures do not include any potential compliance costs that may arise from the EPA's proposed rules that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units.

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

The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental statutes and regulations; the outcome of any legal challenges to environmental rules; changes in generating plants, including unit retirements and replacements and adding or changing fuel sources at existing units, to meet regulatory requirements; changes in FERC rules and regulations; Georgia PSC approvals; changes in the expected environmental compliance program; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered. See Note 3 to the financial statements under "Retail Regulatory Matters – Nuclear Construction" for information regarding additional factors that may impact construction expenditures.

As a result of requirements by the NRC, the Company has established external trust funds for nuclear decommissioning costs. For additional information, see Note 1 to the financial statements under "Nuclear Decommissioning."

In addition, as discussed in Note 2 to the financial statements, the Company provides postretirement benefits to substantially all employees and funds trusts to the extent required by the Georgia PSC and the FERC.

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

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Contractual Obligations

	2015	2016-2017	2018-2019	After 2019	Total
	(in millions)				
Long-term debt[(a)] —					
Principal	$1,148	$1,154	$750	$6,756	$9,808
Interest	342	634	557	5,128	6,661
Preferred and preference stock dividends[(b)]	17	35	35	—	87
Financial derivative obligations[(c)]	31	4	—	—	35
Operating leases[(d)]	25	36	15	14	90
Capital leases[(d)]	6	13	15	6	40
Purchase commitments —					
Capital[(e)]	2,165	4,150	—	—	6,315
Fuel[(f)]	1,805	2,176	1,371	8,722	14,074
Purchased power[(g)]	293	684	606	3,545	5,128
Other[(h)]	92	124	101	272	589
Trusts —					
Nuclear decommissioning[(i)]	5	11	11	110	137
Pension and other postretirement benefit plans[(j)]	44	82	—	—	126
Total	$5,973	$9,103	$3,461	$24,553	$43,090

(a) All amounts are reflected based on final maturity dates. The Company plans to continue to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of January 1, 2015, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk. Long-term debt excludes capital lease amounts (shown separately).

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

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

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

(e) The Company provides estimated capital expenditures for a three-year period, including capital expenditures and compliance costs associated with environmental regulations. These amounts exclude contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements which are reflected separately. At December 31, 2014, significant purchase commitments were outstanding in connection with the construction program. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" herein for additional information.

(f) Includes commitments to purchase coal, nuclear fuel, and natural gas, as well as the related transportation and storage. In most cases, these contracts contain provisions for price escalation, minimum purchase levels, and other financial commitments. Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected for natural gas purchase commitments have been estimated based on the New York Mercantile Exchange future prices at December 31, 2014.

(g) Estimated minimum long-term obligations for various PPA purchases from gas-fired, biomass, and wind-powered facilities. A total of $1.1 billion of biomass PPAs is contingent upon the counterparties meeting specified contract dates for commercial operation and may change as a result of regulatory action. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Renewables Development" for additional information.

(h)

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

(i) Projections of nuclear decommissioning trust fund contributions for Plant Hatch and Plant Vogtle Units 1 and 2 are based on the 2013 ARP. See Note 1 to the financial statements under "Nuclear Decommissioning" for additional information.

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

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Cautionary Statement Regarding Forward-Looking Statements

The Company's 2014 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail rates, economic recovery, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related compliance plans and 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, filings with state and federal regulatory authorities, impact of the TIPA, estimated sales and purchases under power sale and purchase agreements, and estimated construction and other plans and expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, environmental laws including regulation of water, CCR, and emissions of sulfur, nitrogen, CO_2, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, and also changes in tax and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including pending EPA civil action against the Company and IRS and state tax audits;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the last recession, population and business growth (and declines), the effects of energy conservation and efficiency measures, including from the development and deployment of alternative energy sources such as self-generation and distributed generation technologies, and any potential economic impacts resulting from federal fiscal decisions;
- available sources and costs of fuels;
- effects of inflation;
- the ability to control costs and avoid cost overruns during the development and construction of facilities, which include the development and construction of generating facilities with designs that have not been finalized or previously constructed, including changes in labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, non-performance under construction or other agreements, operational readiness, including specialized operator training and required site safety programs, unforeseen engineering or design problems, start-up activities (including major equipment failure and system integration), and/or operational performance (including additional costs to satisfy any operational parameters ultimately adopted by the Georgia PSC);
- the ability to construct facilities in accordance with the requirements of permits and licenses, to satisfy any operational and environmental performance standards, including any PSC requirements and the requirements of tax credits and other incentives, and to integrate facilities into the Southern Company system upon completion of construction;
- investment performance of the Company's employee and retiree benefit plans and nuclear decommissioning trust funds;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate cases related to fuel and other cost recovery mechanisms;
- the ability to successfully operate generating, transmission, and distribution facilities and the successful performance of necessary corporate functions;
-

legal proceedings and regulatory approvals and actions related to Plant Vogtle Units 3 and 4, including Georgia PSC approvals and NRC actions and related legal proceedings involving the commercial parties;

- the inherent risks involved in operating and constructing nuclear generating facilities, including environmental, health, regulatory, natural disaster, terrorism, or financial risks;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;

- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Company's business resulting from cyber intrusion or terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and financial market conditions and the results of financing efforts;
- changes in the Company's credit ratings, including impacts on interest rates, access to capital markets, and collateral requirements;
- the impacts of any sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on currency exchange rates, counterparty performance, and the economy in general, as well as potential impacts on the benefits of the DOE loan guarantees;
- the ability of the Company to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes and other storms, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

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

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STATEMENTS OF INCOME
For the Years Ended December 31, 2014, 2013, and 2012
Georgia Power Company 2014 Annual Report

	2014	2013	2012
	(in millions)		
Operating Revenues:			
Retail revenues	$8,240	$7,620	$7,362
Wholesale revenues, non-affiliates	335	281	281
Wholesale revenues, affiliates	42	20	20
Other revenues	371	353	335
Total operating revenues	8,988	8,274	7,998
Operating Expenses:			
Fuel	2,547	2,307	2,051
Purchased power, non-affiliates	287	224	315
Purchased power, affiliates	701	660	666
Other operations and maintenance	1,902	1,654	1,644
Depreciation and amortization	846	807	745
Taxes other than income taxes	409	382	374
Total operating expenses	6,692	6,034	5,795
Operating Income	2,296	2,240	2,203
Other Income and (Expense):			
Allowance for equity funds used during construction	45	30	53
Interest expense, net of amounts capitalized	(348)	(361)	(366)
Other income (expense), net	(22)	5	(17)
Total other income and (expense)	(325)	(326)	(330)
Earnings Before Income Taxes	1,971	1,914	1,873
Income taxes	729	723	688
Net Income	1,242	1,191	1,185
Dividends on Preferred and Preference Stock	17	17	17
Net Income After Dividends on Preferred and Preference Stock	$1,225	$1,174	$1,168

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

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STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2014, 2013, and 2012
Georgia Power Company 2014 Annual Report

	2014	2013	2012
	(in millions)		
Net Income	$1,242	$1,191	$1,185
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $(3), $-, and $-, respectively	(5)	—	—
Reclassification adjustment for amounts included in net income, net of tax of $1, $1, and $1, respectively	2	2	2
Total other comprehensive income (loss)	(3)	2	2
Comprehensive Income	$1,239	$1,193	$1,187

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

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STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2014, 2013, and 2012
Georgia Power Company 2014 Annual Report

	2014	2013	2012
	(in millions)		
Operating Activities:			
Net income	$1,242	$1,191	$1,185
Adjustments to reconcile net income			
to net cash provided from operating activities —			
Depreciation and amortization, total	1,019	979	912
Deferred income taxes	352	476	377
Allowance for equity funds used during construction	(45)	(30)	(53)
Retail fuel cost over recovery — long-term	(44)	(123)	123
Pension, postretirement, and other employee benefits	19	66	21
Pension and postretirement funding	(156)	(8)	(12)
Other, net	39	38	(12)
Changes in certain current assets and liabilities —			
-Receivables	(248)	(58)	205
-Fossil fuel stock	303	250	(269)
-Prepaid income taxes	(216)	(17)	(7)
-Other current assets	(37)	40	(53)
-Accounts payable	16	67	(165)
-Accrued taxes	17	(14)	(76)
-Accrued compensation	62	(37)	(18)
-Retail fuel cost over-recovery — short-term	(14)	(49)	107
-Other current liabilities	54	(5)	30
Net cash provided from operating activities	2,363	2,766	2,295
Investing Activities:			
Property additions	(2,023)	(1,743)	(1,723)
Investment in restricted cash from pollution control bonds	—	(89)	(284)
Distribution of restricted cash from pollution control bonds	—	89	284
Nuclear decommissioning trust fund purchases	(671)	(706)	(852)
Nuclear decommissioning trust fund sales	669	705	850
Cost of removal, net of salvage	(65)	(59)	(82)
Change in construction payables, net of joint owner portion	(54)	(67)	(149)
Prepaid long-term service agreements	(70)	(18)	(34)
Other investing activities	8	(2)	17
Net cash used for investing activities	(2,206)	(1,890)	(1,973)
Financing Activities:			
Increase (decrease) in notes payable, net	(891)	1,047	(513)
Proceeds —			
Capital contributions from parent company	549	37	42
Pollution control revenue bonds issuances and remarketings	40	194	284
Senior notes issuances	—	850	2,300
FFB loan	1,200	—	—
Redemptions and repurchases —			
Pollution control revenue bonds	(37)	(298)	(284)
Senior notes	—	(1,775)	(850)

Other long-term debt	—	—	(250)
Payment of preferred and preference stock dividends	(17)	(17)	(17)
Payment of common stock dividends	(954)	(907)	(983)
FFB loan issuance costs	(49)	(5)	(3)
Other financing activities	(4)	(17)	(16)
Net cash used for financing activities	(163)	(891)	(290)
Net Change in Cash and Cash Equivalents	(6)	(15)	32
Cash and Cash Equivalents at Beginning of Year	30	45	13
Cash and Cash Equivalents at End of Year	$24	$30	$45
Supplemental Cash Flow Information:			
Cash paid during the period for —			
Interest (net of $18, $14 and $21 capitalized, respectively)	$319	$344	$337
Income taxes (net of refunds)	507	298	312
Noncash transactions — accrued property additions at year-end	154	208	261

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

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BALANCE SHEETS
At December 31, 2014 and 2013
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Assets	2014	2013
	(in millions)	
Current Assets:		
Cash and cash equivalents	$24	$30
Receivables —		
Customer accounts receivable	553	512
Unbilled revenues	201	209
Joint owner accounts receivable	121	67
Other accounts and notes receivable	61	117
Affiliated companies	18	21
Accumulated provision for uncollectible accounts	(6)	(5)
Fossil fuel stock, at average cost	439	742
Materials and supplies, at average cost	438	409
Vacation pay	91	88
Prepaid income taxes	278	97
Other regulatory assets, current	136	106
Other current assets	74	53
Total current assets	2,428	2,446
Property, Plant, and Equipment:		
In service	31,083	30,132
Less accumulated provision for depreciation	11,222	10,970
Plant in service, net of depreciation	19,861	19,162
Other utility plant, net	211	240
Nuclear fuel, at amortized cost	563	523
Construction work in progress	4,031	3,500
Total property, plant, and equipment	24,666	23,425
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	58	46
Nuclear decommissioning trusts, at fair value	789	751
Miscellaneous property and investments	38	44
Total other property and investments	885	841
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	698	718
Prepaid pension costs	—	118
Deferred under recovered regulatory clause revenues	197	—
Other regulatory assets, deferred	1,753	1,113
Other deferred charges and assets	403	246
Total deferred charges and other assets	3,051	2,195
Total Assets	$31,030	$28,907

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

BALANCE SHEETS
At December 31, 2014 and 2013
Georgia Power Company 2014 Annual Report

Liabilities and Stockholder's Equity	2014	2013
	(in millions)	
Current Liabilities:		
Securities due within one year	$1,154	$5
Notes payable	156	1,047
Accounts payable —		
Affiliated	451	417
Other	555	472
Customer deposits	253	246
Other accrued taxes	332	321
Accrued interest	96	91
Accrued vacation pay	63	61
Accrued compensation	153	80
Liabilities from risk management activities	32	13
Other regulatory liabilities, current	21	17
Over recovered regulatory clause revenues, current	—	14
Other current liabilities	204	122
Total current liabilities	3,470	2,906
Long-Term Debt (See accompanying statements)	8,683	8,633
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	5,507	5,200
Deferred credits related to income taxes	106	112
Accumulated deferred investment tax credits	196	203
Employee benefit obligations	903	542
Asset retirement obligations	1,223	1,210
Other cost of removal obligations	46	43
Other deferred credits and liabilities	209	201
Total deferred credits and other liabilities	8,190	7,511
Total Liabilities	20,343	19,050
Preferred Stock (See accompanying statements)	45	45
Preference Stock (See accompanying statements)	221	221
Common Stockholder's Equity (See accompanying statements)	10,421	9,591
Total Liabilities and Stockholder's Equity	$31,030	$28,907
Commitments and Contingent Matters (See notes)		

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

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STATEMENTS OF CAPITALIZATION
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	2014	2013	2014	2013
	(in millions)		(percent of total)	
Long-Term Debt:				
Long-term notes payable —				
Variable rates (0.56% to 0.63% at 1/1/15) due 2016	450	450		
0.625% to 5.25% due 2015	1,050	1,050		
3.00% due 2016	250	250		
5.70% due 2017	450	450		
5.40% due 2018	250	250		
4.25% due 2019	500	500		
2.85% to 5.95% due 2022-2043	3,975	3,975		
Total long-term notes payable	6,925	6,925		
Other long-term debt —				
Pollution control revenue bonds:				
0.80% to 4.00% due 2022-2049	818	818		
Variable rates (0.03% to 0.04% at 1/1/15) due 2015	98	—		
Variable rate (0.04% at 1/1/15) due 2016	4	4		
Variable rate (0.04% at 1/1/14) due 2018	—	20		
Variable rates (0.01% to 0.09% at 1/1/15) due 2022-2052	763	838		
FFB loans (3.00% to 3.86%) due 2044	1,200	—		
Total other long-term debt	2,883	1,680		
Capitalized lease obligations	40	45		
Unamortized debt discount	(11)	(12)		
Total long-term debt (annual interest requirement — $342 million)	9,837	8,638		
Less amount due within one year	1,154	5		
Long-term debt excluding amount due within one year	8,683	8,633	44.8 %	46.7 %
Preferred and Preference Stock:				
Non-cumulative preferred stock				
$25 par value — 6.125%				
Authorized — 50,000,000 shares				
Outstanding — 1,800,000 shares	45	45		
Non-cumulative preference stock				
$100 par value — 6.50%				
Authorized — 15,000,000 shares				
Outstanding — 2,250,000 shares	221	221		
Total preferred and preference stock (annual dividend requirement — $17 million)	266	266	1.4	1.4
Common Stockholder's Equity:				
Common stock, without par value —				
Authorized — 20,000,000 shares				
Outstanding — 9,261,500 shares	398	398		
Paid-in capital	6,196	5,633		
Retained earnings	3,835	3,565		

Accumulated other comprehensive loss	(8)	(5)		
Total common stockholder's equity	10,421	9,591	53.8	51.9
Total Capitalization	$19,370	$18,490	100.0 %	100.0 %

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

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STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
For the Years Ended December 31, 2014, 2013, and 2012
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	Number of Common Shares Issued (in millions)	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance at December 31, 2011	9	$398	$5,522	$3,112	$(9)	$9,023
Net income after dividends on preferred and preference stock	—	—	—	1,168	—	1,168
Capital contributions from parent company	—	—	63	—	—	63
Other comprehensive income (loss)	—	—	—	—	2	2
Cash dividends on common stock	—	—	—	(983)	—	(983)
Balance at December 31, 2012	9	398	5,585	3,297	(7)	9,273
Net income after dividends on preferred and preference stock	—	—	—	1,174	—	1,174
Capital contributions from parent company	—	—	48	—	—	48
Other comprehensive income (loss)	—	—	—	—	2	2
Cash dividends on common stock	—	—	—	(907)	—	(907)
Other	—	—	—	1	—	1
Balance at December 31, 2013	9	398	5,633	3,565	(5)	9,591
Net income after dividends on preferred and preference stock	—	—	—	1,225	—	1,225
Capital contributions from parent company	—	—	563	—	—	563
Other comprehensive income (loss)	—	—	—	—	(3)	(3)
Cash dividends on common stock	—	—	—	(954)	—	(954)
Other	—	—	—	(1)	—	(1)
Balance at December 31, 2014	9	$398	$6,196	$3,835	$(8)	$10,421

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

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NOTES TO FINANCIAL STATEMENTS
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1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES
General
Georgia Power Company (the Company) is a wholly-owned subsidiary of The Southern Company (Southern Company), which is the parent company of the Company and three other traditional operating companies, as well as Southern Power, SCS, SouthernLINC Wireless, Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear, and other direct and indirect subsidiaries. The traditional operating companies – the Company, Alabama Power, Gulf Power, and Mississippi Power – are vertically integrated utilities providing electric service in four Southeastern states. The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located within the State of Georgia and to wholesale customers in the Southeast. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public, and provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary, primarily for Southern Company's investments in leveraged leases. Southern Nuclear operates and provides services to the Southern Company system's nuclear power plants, including the Company's Plant Hatch and Plant Vogtle.
The equity method is used for subsidiaries in which the Company has significant influence but does not control.
The Company is subject to regulation by the FERC and the Georgia PSC. The Company follows GAAP in the U.S. and complies with the accounting policies and practices prescribed by its regulatory commissions. The preparation of financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates. Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation.
Recently Issued Accounting Standards
On May 28, 2014, the Financial Accounting Standards Board issued ASC 606, Revenue from Contracts with Customers. ASC 606 revises the accounting for revenue recognition and is effective for fiscal years beginning after December 15, 2016. The Company continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.
Affiliate Transactions
The Company has an agreement with SCS under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, operations, purchasing, accounting, finance and treasury, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, and other services with respect to business and operations, construction management, and power pool transactions. Costs for these services amounted to $555 million in 2014, $504 million in 2013, and $540 million in 2012. Cost allocation methodologies used by SCS prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, were approved by the SEC. Subsequently, additional cost allocation methodologies have been reported to the FERC and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies.
The Company has an agreement with Southern Nuclear under which the following nuclear-related services are rendered to the Company at cost: general executive and advisory services, general operations, management and technical services, administrative services including procurement, accounting, employee relations, systems and procedures services, strategic planning and budgeting services, and other services with respect to business, operations, and construction management. Costs for these services amounted to $643 million in 2014, $555 million in 2013, and $574 million in 2012.
The Company has entered into several PPAs with Southern Power for capacity and energy. Expenses associated with these PPAs were $144 million, $136 million, and $147 million in 2014, 2013, and 2012, respectively. Additionally,

the Company had $15 million of prepaid capacity expenses included in deferred charges and other assets in the balance sheets at December 31, 2014 and 2013. See Note 7 under "Fuel and Purchased Power Agreements" for additional information.

The Company has a joint ownership agreement with Gulf Power under which Gulf Power owns a 25% portion of Plant Scherer Unit 3. Under this agreement, the Company operates Plant Scherer Unit 3 and Gulf Power reimburses the Company for its 25% proportionate share of the related non-fuel expenses, which were $9 million in 2014, $10 million in 2013, and $7 million in 2012. See Note 4 for additional information.

The Company provides incidental services to and receives such services from other Southern Company subsidiaries which are generally minor in duration and amount. Except as described herein, the Company neither provided nor received any material services to or from affiliates in 2014, 2013, or 2012.

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The traditional operating companies, including the Company, and Southern Power may jointly enter into various types of wholesale energy, natural gas, and certain other contracts, either directly or through SCS as agent. Each participating company may be jointly and severally liable for the obligations incurred under these agreements. See Note 7 under "Fuel and Purchased Power Agreements" for additional information.

Regulatory Assets and Liabilities

The Company is subject to the provisions of the Financial Accounting Standards Board in accounting for the effects of rate regulation. Regulatory assets represent probable future revenues associated with certain costs that are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are expected to be credited to customers through the ratemaking process.

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

	2014	2013	Note
	(in millions)		
Retiree benefit plans	$1,325	$691	(a, j)
Deferred income tax charges	668	684	(b, j)
Deferred income tax charges — Medicare subsidy	34	38	(c)
Loss on reacquired debt	163	181	(d, j)
Asset retirement obligations	108	137	(b, j)
Fuel-hedging (realized and unrealized) losses	29	22	(e, j)
Vacation pay	91	88	(f, j)
Building lease	31	37	(g, j)
Cancelled construction projects	67	70	(h)
Remaining net book value of retired units	25	28	(i)
Storm damage reserves	98	37	(c)
Other regulatory assets	63	49	(c)
Other cost of removal obligations	(60)	(58)	(b)
Deferred income tax credits	(106)	(112)	(b, j)
Other regulatory liabilities	(7)	(6)	(e, j)
Total regulatory assets (liabilities), net	$2,529	$1,886	

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

(a) Recovered and amortized over the average remaining service period which may range up to 13 years. See Note 2 for additional information.

(b) Asset retirement and other cost of removal obligations and deferred income tax assets are recovered, and deferred income tax liabilities are amortized over the related property lives, which may range up to 70 years. Asset retirement and removal liabilities will be settled and trued up following completion of the related activities. At December 31, 2014, other cost of removal obligations included $29 million that will be amortized over the remaining two-year period of January 2015 through December 2016 in accordance with the Company's 2013 ARP.

(c) Recorded and recovered or amortized as approved by the Georgia PSC over periods generally not exceeding eight years.

(d) Recovered over either the remaining life of the original issue or, if refinanced, over the remaining life of the new issue, which currently does not exceed 38 years.

(e) Fuel-hedging assets and liabilities are recorded over the life of the underlying hedged purchase contracts, which generally do not exceed two years. Upon final settlement, actual costs incurred are recovered through the Company's fuel cost recovery mechanism.

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

(g) See Note 6 under "Capital Leases." Recovered over the remaining life of the building through 2020.

(h) Costs associated with construction of environmental controls that will not be completed as a result of unit retirements are being amortized as approved by the Georgia PSC over periods not exceeding nine years or through 2022.

(i) Amortized as approved by the Georgia PSC over periods not exceeding 10 years or through 2022.

(j) Generally not earning a return as they are excluded from rate base or are offset in rate base by a corresponding asset or liability.

In the event that a portion of the Company's operations is no longer subject to applicable accounting rules for rate regulation, the Company would be required to write off to income or reclassify to accumulated OCI related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the Company would be required to determine if any

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impairment to other assets, including plant, exists and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are to be reflected in rates. See Note 3 under "Retail Regulatory Matters" for additional information.

Revenues

Wholesale capacity revenues from PPAs are recognized either on a levelized basis over the appropriate contract period or the amount billable under the contract terms. Energy and other revenues are recognized as services are provided. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between the actual recoverable costs and amounts billed in current regulated rates.

The Company has a diversified base of customers. No single customer or industry comprises 10% or more of revenues. For all periods presented, uncollectible accounts averaged less than 1% of revenues.

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense 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. See Note 3 under "Retail Regulatory Matters – Nuclear Waste Fund Fee" for additional information.

Income and Other Taxes

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

Federal ITCs utilized are deferred and amortized to income as a credit to reduce depreciation over the average life of the related property. State ITCs are recognized in the period in which the credits are claimed on the state income tax return. A portion of the ITCs available to reduce income taxes payable was not utilized currently and will be carried forward and utilized in future years.

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

Property, Plant, and Equipment

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

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

	2014	2013
	(in millions)	
Generation	$15,201	$14,872
Transmission	5,086	4,859
Distribution	8,913	8,620
General	1,855	1,753
Plant acquisition adjustment	28	28
Total plant in service	$31,083	$30,132

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to other operations and maintenance expenses as incurred or performed with the exception of certain generating plant maintenance costs. As mandated by the Georgia PSC, the Company defers and amortizes nuclear refueling outage costs over the unit's operating cycle. The refueling cycles are 18 and 24 months for Plant Vogtle Units 1 and 2 and Plant Hatch Units 1 and 2, respectively.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 2.7% in 2014, 3.0% in 2013, and 2.9% in 2012. Depreciation studies are conducted periodically to update the

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composite rates that are approved by the Georgia PSC and the FERC. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation are removed from the balance sheet accounts, and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired.

In 2009, the Georgia PSC approved an accounting order allowing the Company to amortize a portion of its regulatory liability related to other cost of removal obligations. Under the terms of the Company's Alternate Rate Plan for the years 2011 through 2013 (2010 ARP), the Company amortized approximately $31 million annually of the remaining regulatory liability related to other cost of removal obligations over the three years ended December 31, 2013. Under the terms of the 2013 ARP, an additional $14 million is being amortized annually over the three years ending December 31, 2016.

Asset Retirement Obligations and Other Costs of Removal

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

The ARO liability relates to the decommissioning of the Company's nuclear facilities, which include the Company's ownership interests in Plant Hatch and Plant Vogtle Units 1 and 2, as well as various landfill sites, ash ponds, underground storage tanks, and asbestos removal. The Company also has identified retirement obligations related to certain transmission and distribution facilities, including the disposal of polychlorinated biphenyls in certain transformers; leasehold improvements; equipment on customer property; and property associated with the Company's rail lines and natural gas pipelines. However, liabilities for the removal of these assets have not been recorded because the settlement timing for the retirement obligations related to these assets is indeterminable and, therefore, the fair value of the retirement obligations cannot be reasonably estimated. A liability for these AROs will be recognized when sufficient information becomes available to support a reasonable estimation of the ARO. The Company will continue to recognize in the statements of income allowed removal costs in accordance with its regulatory treatment. Any differences between costs recognized in accordance with accounting standards related to asset retirement and environmental obligations and those reflected in rates are recognized as either a regulatory asset or liability in the balance sheets as ordered by the Georgia PSC. See "Nuclear Decommissioning" herein for additional information on amounts included in rates.

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

	2014	2013
	(in millions)	
Balance at beginning of year	$1,222	$1,105
Liabilities incurred	9	2
Liabilities settled	(12)	(13)
Accretion	53	55
Cash flow revisions	(17)	73
Balance at end of year	$1,255	$1,222

The 2014 decrease in cash flow revisions is primarily related to settled AROs for asbestos remediation. The 2013 increase in cash flow revisions is related to updated estimates for ash ponds in connection with the retirement of certain coal-fired generating units and revisions to the nuclear decommissioning AROs based on the latest decommissioning study.

On December 19, 2014, the EPA issued the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule), but has not yet published it in the Federal Register. The CCR Rule will regulate the disposal of CCR, including coal ash and gypsum, as non-hazardous solid waste in landfills and surface impoundments at active generating power plants. The ultimate impact of the CCR Rule cannot be determined at this time and will depend on the Company's ongoing review of the CCR Rule, the results of initial and ongoing minimum criteria assessments, and the outcome of legal challenges. The cost and timing of potential ash pond closure and ongoing monitoring activities that may be required in connection with the CCR Rule is also uncertain; however, the Company has developed a preliminary nominal dollar estimate of costs associated with closure and groundwater monitoring of ash ponds in place of approximately $390 million and ongoing post-closure care of approximately $62 million. The Company has previously recorded AROs associated with ash ponds of $500 million, or $458 million on a nominal dollar basis, based on existing state requirements. During 2015, the Company will record AROs for any incremental estimated

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closure costs resulting from acceleration in the timing of any currently planned closures and for differences between existing state requirements and the requirements of the CCR Rule. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates.

Nuclear Decommissioning

The NRC requires licensees of commercial nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. The Company has external trust funds (Funds) to comply with the NRC's regulations. Use of the Funds is restricted to nuclear decommissioning activities. The Funds are managed and invested in accordance with applicable requirements of various regulatory bodies, including the NRC, the FERC, and the Georgia PSC, as well as the IRS. While the Company is allowed to prescribe an overall investment policy to the Funds' managers, the Company and its affiliates are not allowed to engage in the day-to-day management of the Funds or to mandate individual investment decisions. Day-to-day management of the investments in the Funds is delegated to unrelated third party managers with oversight by the management of the Company. The Funds' managers are authorized, within certain investment guidelines, to actively buy and sell securities at their own discretion in order to maximize the return on the Funds' investments. The Funds are invested in a tax-efficient manner in a diversified mix of equity and fixed income securities and are reported as trading securities.

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

The Funds participate in a securities lending program through the managers of the Funds. Under this program, the Funds' investment securities are loaned to institutional investors for a fee. Securities loaned are fully collateralized by cash, letters of credit, and/or securities issued or guaranteed by the U.S. government or its agencies or instrumentalities. As of December 31, 2014 and 2013, approximately $51 million and $32 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 $52 million and $33 million at December 31, 2014 and 2013, 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, 2014, investment securities in the Funds totaled $789 million, consisting of equity securities of $303 million, debt securities of $475 million, and $11 million of other securities. At December 31, 2013, investment securities in the Funds totaled $751 million, consisting of equity securities of $330 million, debt securities of $397 million, and $24 million of other securities. 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 $669 million, $705 million, and $850 million in 2014, 2013, and 2012, respectively, all of which were reinvested. For 2014, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $44 million, of which an immaterial amount related to unrealized gains and losses on securities held in the Funds at December 31, 2014. For 2013, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $61 million, of which $34 million related to unrealized gains on securities held in the Funds at December 31, 2013. For 2012, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $67 million, of which $25 million related to unrealized losses on securities held in the Funds at December 31, 2012. While the investment securities held in the Funds are reported as trading securities, the Funds continue to be managed with a long-term focus. Accordingly, all purchases and sales within the Funds are presented separately in the statements of cash flows as investing cash flows, consistent with the nature of the securities and purpose for which the securities were acquired.

The NRC's minimum external funding requirements are based on a generic estimate of the cost to decommission only the radioactive portions of a nuclear unit based on the size and type of reactor. The Company has filed plans with the

NRC designed to ensure that, over time, the deposits and earnings of the Funds will provide the minimum funding amounts prescribed by the NRC.

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Site study cost is the estimate to decommission a specific facility as of the site study year. The decommissioning cost estimates are based on prompt dismantlement and removal of the plant from service. The actual decommissioning costs may vary from these estimates because of changes in the assumed date of decommissioning, changes in NRC requirements, or changes in the assumptions used in making these estimates. The estimated costs of decommissioning are based on the most current study performed in 2012. The site study costs and external trust funds for decommissioning as of December 31, 2014 based on the Company's ownership interests were as follows:

	Plant Hatch	Plant Vogtle Units 1 and 2
Decommissioning periods:		
Beginning year	2034	2047
Completion year	2068	2072
	(in millions)	
Site study costs:		
Radiated structures	$549	$453
Spent fuel management	131	115
Non-radiated structures	51	76
Total site study costs	$731	$644
External trust funds	$496	$293

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

Allowance for Funds Used During Construction

In accordance with regulatory treatment, the Company records AFUDC, which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently from such allowance, AFUDC increases the revenue requirement and is recovered over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in calculating taxable income. For the years 2014, 2013, and 2012, the average AFUDC rates were 5.6%, 5.3%, and 6.8%, respectively, and AFUDC capitalized was $62 million, $44 million, and $75 million, respectively. AFUDC, net of income taxes, was 4.6%, 3.3%, and 5.7% of net income after dividends on preferred and preference stock for 2014, 2013, and 2012, respectively. See Note 3 under "Retail Regulatory Matters – Nuclear Construction" for additional information on the inclusion of construction costs related to Plant Vogtle Units 3 and 4 in rate base effective January 1, 2011.

Impairment of Long-Lived Assets and Intangibles

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

Storm Damage Recovery

The Company defers and recovers certain costs related to damages from major storms as mandated by the Georgia PSC. Beginning January 1, 2014, the Company is accruing $30 million annually under the 2013 ARP that is recoverable through base rates. As of December 31, 2014 and December 31, 2013, the balance in the regulatory asset related to storm damage was $98 million and $37 million, respectively, with approximately $30 million included in other regulatory assets, current for both years and approximately $68 million and $7 million included in other regulatory assets, deferred, respectively. The Company expects

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the Georgia PSC to periodically review and adjust, if necessary, the amounts collected in rates for storm damage costs. As a result of the regulatory treatment, costs related to storms are generally not expected to have a material impact on the Company's financial statements.

Environmental Remediation Recovery

The Company maintains a reserve for environmental remediation as mandated by the Georgia PSC. In December 2013, the Georgia PSC approved the 2013 ARP including the recovery of approximately $2 million annually through the environmental compliance cost recovery (ECCR) tariff from 2014 through 2016. The Company recovered approximately $3 million annually through the ECCR tariff from 2011 through 2013 under the 2010 ARP. The Company recognizes a liability for environmental remediation costs only when it determines a loss is probable and reduces the reserve as expenditures are incurred. Any difference between the liabilities accrued and cost recovered through rates is deferred as a regulatory asset or liability. The annual recovery amount is expected to be reviewed by the Georgia PSC and adjusted in future regulatory proceedings. As a result of this regulatory treatment, environmental remediation liabilities generally are not expected to have a material impact on the Company's financial statements. As of December 31, 2014, the balance of the environmental remediation liability was $22 million, with approximately $2 million included in other regulatory assets, current and approximately $14 million included as other regulatory assets, deferred. See Note 3 under "Environmental Matters – Environmental Remediation" for additional information.

Cash and Cash Equivalents

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

Materials and Supplies

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

Fuel Inventory

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

Financial Instruments

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

The Company does not offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. Additionally, the Company had no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2014.

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

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Comprehensive Income
The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income, changes in the fair value of qualifying cash flow hedges, and reclassifications for amounts included in net income.
2. RETIREMENT BENEFITS
The Company has a defined benefit, trusteed, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). In December 2014, the Company voluntarily contributed $150 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2015. The Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The Company funds its other postretirement trusts to the extent required by the Georgia PSC and the FERC. For the year ending December 31, 2015, other postretirement trust contributions are expected to total approximately $17 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 2011 for the 2012 plan year using discount rates for the pension plans and the other postretirement benefit plans of 4.98% and 4.87%, respectively, and an annual salary increase of 3.84%.

	2014		2013		2012	
Discount rate:						
Pension plans	4.18	%	5.02	%	4.27	%
Other postretirement benefit plans	4.03		4.85		4.04	
Annual salary increase	3.59		3.59		3.59	
Long-term return on plan assets:						
Pension plans	8.20		8.20		8.20	
Other postretirement benefit plans	6.75		6.74		7.24	

The Company estimates the expected rate of return on pension plan and other postretirement benefit plan assets using a financial model to project the expected return on each current investment portfolio. The analysis projects an expected rate of return on each of seven different asset classes in order to arrive at the expected return on the entire portfolio relying on each trust's target asset allocation and reasonable capital market assumptions. The financial model is based on four key inputs: anticipated returns by asset class (based in part on historical returns), each trust's target asset allocation, an anticipated inflation rate, and the projected impact of a periodic rebalancing of each trust's portfolio.
For purposes of its December 31, 2014 measurement date, the Company adopted new mortality tables for its pension plans and retiree life and medical plans, which reflect increased life expectancies in the U.S. The adoption of new mortality tables increased the projected benefit obligations for the Company's pension plans and other postretirement benefit plans by approximately $226 million and $46 million, respectively.
An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) was a weighted average medical care cost trend rate. The weighted average medical care cost trend rates used in measuring the APBO as of December 31, 2014 were as follows:

	Initial Cost Trend Rate	Ultimate Cost Trend Rate	Year That Ultimate

					Rate is Reached
Pre-65	9.00	%	4.50	%	2024
Post-65 medical	6.00		4.50		2024
Post-65 prescription	6.75		4.50		2024

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An annual increase or decrease in the assumed medical care cost trend rate of 1% would affect the APBO and the service and interest cost components at December 31, 2014 as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$69	$(58)
Service and interest costs	3	(2)

Pension Plans

The total accumulated benefit obligation for the pension plans was $3.5 billion at December 31, 2014 and $2.9 billion at December 31, 2013. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2014 and 2013 were as follows:

	2014	2013
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	$3,116	$3,312
Service cost	62	69
Interest cost	153	138
Benefits paid	(149)	(141)
Actuarial (gain) loss	599	(262)
Balance at end of year	3,781	3,116
Change in plan assets		
Fair value of plan assets at beginning of year	3,085	2,827
Actual return on plan assets	285	387
Employer contributions	162	12
Benefits paid	(149)	(141)
Fair value of plan assets at end of year	3,383	3,085
Accrued liability	$(398)	$(31)

At December 31, 2014, the projected benefit obligations for the qualified and non-qualified pension plans were $3.6 billion and $165 million, respectively. All pension plan assets are related to the qualified pension plan.

Amounts recognized in the balance sheets at December 31, 2014 and 2013 related to the Company's pension plans consist of the following:

	2014	2013
	(in millions)	
Prepaid pension costs	$—	$118
Other regulatory assets, deferred	1,102	610
Current liabilities, other	(12)	(12)
Employee benefit obligations	(386)	(137)

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Presented below are the amounts included in regulatory assets at December 31, 2014 and 2013 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 2015.

	2014	2013	Estimated Amortization in 2015
	(in millions)		
Prior service cost	$17	$26	$9
Net (gain) loss	1,085	584	76
Regulatory assets	$1,102	$610	

The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2014 and 2013 are presented in the following table:

	2014	2013
	(in millions)	
Regulatory assets:		
Beginning balance	$610	$1,132
Net (gain) loss	543	(438)
Reclassification adjustments:		
Amortization of prior service costs	(10)	(10)
Amortization of net gain (loss)	(41)	(74)
Total reclassification adjustments	(51)	(84)
Total change	492	(522)
Ending balance	$1,102	$610

Components of net periodic pension cost were as follows:

	2014	2013	2012
	(in millions)		
Service cost	$62	$69	$60
Interest cost	153	138	141
Expected return on plan assets	(228)	(212)	(221)
Recognized net loss	41	74	33
Net amortization	10	10	12
Net periodic pension cost	$38	$79	$25

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

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Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2014, estimated benefit payments were as follows:

	Benefit Payments (in millions)
2015	$199
2016	169
2017	177
2018	183
2019	190
2020 to 2024	1,042

Other Postretirement Benefits

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2014 and 2013 were as follows:

	2014	2013
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	$723	$800
Service cost	6	7
Interest cost	34	31
Benefits paid	(44)	(45)
Actuarial (gain) loss	142	(73)
Retiree drug subsidy	3	3
Balance at end of year	864	723
Change in plan assets		
Fair value of plan assets at beginning of year	407	382
Actual return on plan assets	21	56
Employer contributions	8	11
Benefits paid	(41)	(42)
Fair value of plan assets at end of year	395	407
Accrued liability	$(469)	$(316)

Amounts recognized in the balance sheets at December 31, 2014 and 2013 related to the Company's other postretirement benefit plans consist of the following:

	2014	2013
	(in millions)	
Other regulatory assets, deferred	$213	$69
Employee benefit obligations	(469)	(316)

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Presented below are the amounts included in regulatory assets at December 31, 2014 and 2013 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 2015.

	2014	2013	Estimated Amortization in 2015
	(in millions)		
Prior service cost	$(5)	$(4)	$—
Net (gain) loss	218	73	11
Regulatory assets	$213	$69	

The changes in the balance of regulatory assets related to the other postretirement benefit plans for the plan years ended December 31, 2014 and 2013 are presented in the following table:

	2014	2013
	(in millions)	
Regulatory assets:		
Beginning balance	$69	$187
Net (gain) loss	146	(106)
Reclassification adjustments:		
Amortization of transition obligation	—	(4)
Amortization of net gain (loss)	(2)	(8)
Total reclassification adjustments	(2)	(12)
Total change	144	(118)
Ending balance	$213	$69

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

	2014	2013	2012
	(in millions)		
Service cost	$6	$7	$7
Interest cost	34	31	37
Expected return on plan assets	(25)	(24)	(29)
Net amortization	2	12	10
Net periodic postretirement benefit cost	$17	$26	$25

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)		
2015	$53	$(4)	$49
2016	56	(5)	51
2017	57	(5)	52
2018	59	(6)	53
2019	59	(6)	53
2020 to 2024	289	(32)	257

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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. 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, 2014 and 2013, along with the targeted mix of assets for each plan, is presented below:

	Target		2014		2013	
Pension plan assets:						
Domestic equity	26	%	30	%	31	%
International equity	25		23		25	
Fixed income	23		27		23	
Special situations	3		1		1	
Real estate investments	14		14		14	
Private equity	9		5		6	
Total	100	%	100	%	100	%
Other postretirement benefit plan assets:						
Domestic equity	40	%	38	%	36	%
International equity	21		26		30	
Domestic fixed income	24		24		21	
Global fixed income	8		7		8	
Special situations	1		—		—	
Real estate investments	4		4		3	
Private equity	2		1		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.

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- 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, 2014 and 2013. 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.

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The fair values of pension plan assets as of December 31, 2014 and 2013 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, 2014:	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*	$595	$246	$—	$841
International equity*	373	344	—	717
Fixed income:				
U.S. Treasury, government, and agency bonds	—	244	—	244
Mortgage- and asset-backed securities	—	66	—	66
Corporate bonds	—	398	—	398
Pooled funds	—	179	—	179
Cash equivalents and other	1	230	—	231
Real estate investments	102	—	391	493
Private equity	—	—	199	199
Total	$1,071	$1,707	$590	$3,368
Liabilities:				
Derivatives	$(1)	$—	$—	$(1)
Total	$1,070	$1,707	$590	$3,367

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

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	Fair Value Measurements Using			
As of December 31, 2013:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in millions)			
Assets:				
Domestic equity*	$506	$296	$—	$802
International equity*	389	359	—	748
Fixed income:				
U.S. Treasury, government, and agency bonds	—	212	—	212
Mortgage- and asset-backed securities	—	55	—	55
Corporate bonds	—	346	—	346
Pooled funds	—	166	—	166
Cash equivalents and other	—	79	—	79
Real estate investments	92	—	353	445
Private equity	—	—	202	202
Total	$987	$1,513	$555	$3,055
Liabilities:				
Derivatives	$—	$(1)	$—	$(1)
Total	$987	$1,512	$555	$3,054

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

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, 2014 and 2013 were as follows:

	2014		2013	
	Real Estate Investments	Private Equity	Real Estate Investments	Private Equity
	(in millions)			
Beginning balance	$353	$202	$299	$211
Actual return on investments:				
Related to investments held at year end	23	15	25	3
Related to investments sold during the year	12	(6)	10	17
Total return on investments	35	9	35	20
Purchases, sales, and settlements	3	(12)	19	(29)
Ending balance	$391	$199	$353	$202

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The fair values of other postretirement benefit plan assets as of December 31, 2014 and 2013 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, 2014:	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*	$53	$40	$—	$93
International equity*	11	45	—	56
Fixed income:				
U.S. Treasury, government, and agency bonds	—	7	—	7
Mortgage- and asset-backed securities	—	2	—	2
Corporate bonds	—	12	—	12
Pooled funds	—	29	—	29
Cash equivalents and other	8	11	—	19
Trust-owned life insurance	—	162	—	162
Real estate investments	3	—	12	15
Private equity	—	—	6	6
Total	$75	$308	$18	$401

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

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As of December 31, 2013:	Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in millions)			
Assets:				
Domestic equity*	$74	$25	$—	$99
International equity*	12	57	—	69
Fixed income:				
U.S. Treasury, government, and agency bonds	—	7	—	7
Mortgage- and asset-backed securities	—	2	—	2
Corporate bonds	—	11	—	11
Pooled funds	—	34	—	34
Cash equivalents and other	—	6	—	6
Trust-owned life insurance	—	158	—	158
Real estate investments	3	—	11	14
Private equity	—	—	6	6
Total	$89	$300	$17	$406

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

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, 2014 and 2013 were as follows:

	2014 Real Estate Investments	Private Equity	2013 Real Estate Investments	Private Equity
	(in millions)			
Beginning balance	$11	$6	$10	$7
Actual return on investments:				
Related to investments held at year end	1	—	1	—
Related to investments sold during the year	—	—	—	—
Total return on investments	1	—	1	—
Purchases, sales, and settlements	—	—	—	(1)
Ending balance	$12	$6	$11	$6

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides an 85% matching contribution on up to 6% of an employee's base salary. Total matching contributions made to the plan for 2014, 2013, and 2012 were $25 million, $24 million, and $24 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has occurred throughout the U.S. This litigation has included claims for damages alleged to have

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been caused by CO_2 and other emissions, CCR, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements.

Environmental Matters

New Source Review Actions

As part of a nationwide enforcement initiative against the electric utility industry which began in 1999, the EPA brought civil enforcement actions in federal district court against the Company alleging violations of the New Source Review provisions of the Clean Air Act at certain coal-fired electric generating units, including a unit co-owned by Gulf Power. These civil actions seek penalties and injunctive relief, including orders requiring installation of the best available control technologies at the affected units. The case against the Company (including claims related to a unit co-owned by Gulf Power) has been administratively closed in the U.S. District Court for the Northern District of Georgia since 2001.

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

Environmental Remediation

The Company must comply with environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company may also incur substantial costs to clean up properties. See Note 1 under "Environmental Remediation Recovery" for additional information.

The Company has been designated or identified as a potentially responsible party (PRP) at sites governed by the Georgia Hazardous Site Response Act and/or by the federal Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), including a site in Brunswick, Georgia on the CERCLA National Priorities List. The parties have completed the removal of wastes from the Brunswick site as ordered by the EPA. Additional cleanup and claims for recovery of natural resource damages at this site or for the assessment and potential cleanup of other sites are anticipated.

The Company and numerous other entities have been designated by the EPA as PRPs at the Ward Transformer Superfund site located in Raleigh, North Carolina. In 2011, the EPA issued a Unilateral Administrative Order (UAO) to the Company and 22 other parties, ordering specific remedial action of certain areas at the site. Later in 2011, the Company filed a response with the EPA stating it has sufficient cause to believe it is not a liable party under CERCLA. The EPA notified the Company in 2011 that it is considering enforcement options against the Company and other non-complying UAO recipients. If the EPA pursues enforcement actions and the court determines that a respondent failed to comply with the UAO without sufficient cause, the EPA may also seek civil penalties of up to $37,500 per day for the violation and punitive damages of up to three times the costs incurred by the EPA as a result of the party's failure to comply with the UAO.

In addition to the EPA's action at this site, the Company, along with many other parties, was sued in a private action by several existing PRPs for cost recovery related to the removal action. In February 2013, the U.S. District Court for the Eastern District of North Carolina Western Division granted the Company's summary judgment motion, ruling that the Company has no liability in the private action. In May 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 Company's regulatory treatment for environmental remediation expenses described in Note 1 under "Environmental Remediation Recovery," these matters are not expected to have a material impact on the Company's financial statements.

Nuclear Fuel Disposal Costs

Acting through the DOE and pursuant to the Nuclear Waste Policy Act of 1982, the U.S. government entered into contracts with the Company that require the DOE to dispose of spent nuclear fuel and high level radioactive waste generated at Plant Hatch and Plant Vogtle Units 1 and 2 beginning no later than January 31, 1998. The DOE has yet to commence the performance of its

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contractual and statutory obligation to dispose of spent nuclear fuel. Consequently, the Company pursued and continues to pursue legal remedies against the U.S. government for its partial breach of contract.
As a result of its first lawsuit, the Company recovered approximately $27 million, based on its ownership interests, representing the vast majority of the Company's direct costs of the expansion of spent nuclear fuel storage facilities at Plant Hatch and Plant Vogtle Units 1 and 2 from 1998 through 2004. The proceeds were received in 2012 and credited to the Company accounts where the original costs were charged and were used to reduce rate base, fuel, and cost of service for the benefit of customers.
On December 12, 2014, the Court of Federal Claims entered a judgment in favor of the Company in its second spent nuclear fuel lawsuit seeking damages for the period from January 1, 2005 through December 31, 2010. The Company was awarded approximately $18 million, based on its ownership interests. No amounts have been recognized in the financial statements as of December 31, 2014. The final outcome of this matter cannot be determined at this time; however, no material impact on the Company's net income is expected.
On March 4, 2014, the Company filed additional lawsuits against the U.S. government for the costs of continuing to store spent nuclear fuel at Plant Hatch and Plant Vogtle Units 1 and 2 for the period from January 1, 2011 through December 31, 2013. 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, 2014 for any potential recoveries from the additional lawsuits. The final outcome of these matters cannot be determined at this time; however, no material impact on the Company's net income is expected as a significant portion of any damage amounts collected from the government is expected to be credited to the Company accounts where the original costs were charged and used to reduce rate base, fuel, and cost of service for the benefit of customers.
On-site dry spent fuel storage facilities are operational at Plant Vogtle Units 1 and 2 and Plant Hatch. Facilities at the plants can be expanded to accommodate spent fuel through the expected life of each plant.
Retail Regulatory Matters
Rate Plans
In December 2013, the Georgia PSC voted to approve the 2013 ARP. The 2013 ARP reflects the settlement agreement among the Company, the Georgia PSC's Public Interest Advocacy Staff, and 11 of the 13 intervenors, which was filed with the Georgia PSC in November 2013.
On January 1, 2014, in accordance with the 2013 ARP, the Company increased its tariffs as follows: (1) traditional base tariff rates by approximately $80 million; (2) ECCR tariff by approximately $25 million; (3) Demand-Side Management (DSM) tariffs by approximately $1 million; and (4) Municipal Franchise Fee (MFF) tariff by approximately $4 million, for a total increase in base revenues of approximately $110 million.
On February 19, 2015, in accordance with the 2013 ARP, the Georgia PSC approved adjustments to traditional base, ECCR, DSM, and MFF tariffs effective January 1, 2015 as follows:
- Traditional base tariffs by approximately $107 million to cover additional capacity costs;
- ECCR tariff by approximately $23 million;
- DSM tariffs by approximately $3 million; and
- MFF tariff by approximately $3 million to reflect the adjustments above.

The sum of these adjustments resulted in a base revenue increase of approximately $136 million in 2015.
The 2016 base rate increase, which was approved in the 2013 ARP, will be determined through a compliance filing expected to be filed in late 2015, and will be subject to review by the Georgia PSC.
Under the 2013 ARP, the Company'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 the Company. There will be no recovery of any earnings shortfall below 10.00% on an actual basis. However, if at any time during the term of the 2013 ARP, the Company projects that its retail earnings will be below 10.00% for any calendar year, it may petition the Georgia PSC for implementation of the Interim Cost Recovery (ICR) tariff that would be used to adjust the Company's earnings back to a 10.00% retail ROE. The Georgia

PSC would have 90 days to rule on the Company's request. The ICR tariff will expire at the earlier of January 1, 2017 or the end of the calendar year in which the ICR tariff becomes effective. In lieu of requesting implementation of an ICR tariff, or if the Georgia PSC chooses not to implement the ICR tariff, the Company may file a full rate case. In 2014, the Company's retail ROE exceeded 12.00%, and the Company expects to refund to retail customers approximately $13 million in 2015, subject to review and approval by the Georgia PSC.

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

Integrated Resource Plans

In July 2013, the Georgia PSC approved the Company's latest triennial Integrated Resource Plan (2013 IRP) including the Company's request to decertify 16 coal- and oil-fired units totaling 2,093 MWs. Several factors, including the cost to comply with existing and future environmental regulations, recent and forecasted economic conditions, and lower natural gas prices, contributed to the decision to close these units.

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 (250 MWs) was extended from December 31, 2013 as specified in the final order in the 2011 Integrated Resource Plan Update (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) were 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 in September 2013 to allow for necessary transmission system reliability improvements. In July 2013, the Georgia PSC approved the switch to natural gas as the primary fuel for Plant Yates Units 6 and 7. In September 2013, Plant Branch Unit 2 (319 MWs) was retired as approved by the Georgia PSC in the 2011 IRP Update in order to comply with the State of Georgia's Multi-Pollutant Rule.

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 the Company's next base rate case, which the Company expects to file in 2016 (2016 Rate Case). In the 2013 IRP, the Georgia PSC also deferred decisions regarding the recovery of any fuel related costs that could be incurred in connection with the retirement units to be addressed in future fuel cases.

On July 1, 2014, the Georgia PSC approved the Company's request to cancel the proposed biomass fuel conversion of Plant Mitchell Unit 3 (155 MWs) because it would not be cost effective for customers. The Company expects to request decertification of Plant Mitchell Unit 3 in connection with the triennial Integrated Resource Plan to be filed in 2016. The Company plans to continue to operate the unit as needed until the MATS rule becomes effective in April 2015.

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

Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Georgia PSC. The Georgia PSC approved a reduction in the Company's total annual billings of approximately $567 million effective June 1, 2012, with an additional $122 million reduction effective January 1, 2013 through June 1, 2014. Under an Interim Fuel Rider, the Company continues to be allowed to adjust its fuel cost recovery rates prior to the next fuel case if the under or over recovered fuel balance exceeds $200 million. The Company's fuel cost recovery includes costs associated with a natural gas hedging program as revised and approved by the Georgia PSC in February 2013, requiring it to use options and hedges within a 24-month time horizon. See Note 11 under "Energy-Related Derivatives" for additional information. On January 20, 2015, the Georgia PSC approved the deferral of the Company's next fuel case filing until at least June 30, 2015.

The Company's under recovered fuel balance totaled approximately $199 million at December 31, 2014 and is included in current assets and other deferred charges and assets. At December 31, 2013, the Company's over recovered fuel balance totaled approximately $58 million and was included in current liabilities and other deferred credits and liabilities.

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

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Nuclear Construction
In 2008, the Company, acting for itself and as agent for Oglethorpe Power Corporation (OPC), the Municipal Electric Authority of Georgia (MEAG Power), and the City of Dalton, Georgia (Dalton), acting by and through its Board of Water, Light, and Sinking Fund Commissioners (collectively, Vogtle Owners), entered into an agreement with a consortium consisting of Westinghouse Electric Company LLC (Westinghouse) and Stone & Webster, Inc., a subsidiary of The Shaw Group Inc., which was acquired by Chicago Bridge & Iron Company N.V. (CB&I) (collectively, Contractor), pursuant to which the Contractor agreed to design, engineer, procure, construct, and test two AP1000 nuclear units (with electric generating capacity of approximately 1,100 MWs each) and related facilities at Plant Vogtle (Vogtle 3 and 4 Agreement). Under the terms of the Vogtle 3 and 4 Agreement, the Vogtle Owners agreed to pay a purchase price that is subject to certain price escalations and adjustments, including fixed escalation amounts and index-based adjustments, as well as adjustments for change orders, and performance bonuses for early completion and unit performance. The Vogtle 3 and 4 Agreement also provides for liquidated damages upon the Contractor's failure to fulfill the schedule and performance guarantees. The Contractor's liability to the Vogtle Owners for schedule and performance liquidated damages and warranty claims is subject to a cap. In addition, the Vogtle 3 and 4 Agreement provides for limited cost sharing by the Vogtle Owners for Contractor costs under certain conditions (which have not occurred), with maximum additional capital costs under this provision attributable to the Company (based on the Company's ownership interest) of approximately $114 million. Each Vogtle Owner is severally (and not jointly) liable for its proportionate share, based on its ownership interest, of all amounts owed to the Contractor under the Vogtle 3 and 4 Agreement. The Company's proportionate share is 45.7%.
Certain payment obligations of Westinghouse and Stone & Webster, Inc. under the Vogtle 3 and 4 Agreement are guaranteed by Toshiba Corporation and CB&I's The Shaw Group Inc., respectively. In the event of certain credit rating downgrades of any Vogtle Owner, such Vogtle Owner will be required to provide a letter of credit or other credit enhancement. The Vogtle Owners may terminate the Vogtle 3 and 4 Agreement at any time for their convenience, provided that the Vogtle Owners will be required to pay certain termination costs. The Contractor may terminate the Vogtle 3 and 4 Agreement under certain circumstances, including certain Vogtle Owner suspension or delays of work, action by a governmental authority to permanently stop work, certain breaches of the Vogtle 3 and 4 Agreement by the Vogtle Owners, Vogtle Owner insolvency, and certain other events.
In 2009, the NRC issued an Early Site Permit and Limited Work Authorization which allowed limited work to begin on Plant Vogtle Units 3 and 4. The NRC certified the Westinghouse Design Control Document, as amended (DCD), for the AP1000 nuclear reactor design, in late 2011, and issued combined construction and operating licenses (COLs) in early 2012. Receipt of the COLs allowed full construction to begin. There have been technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4, at the federal and state level, and additional challenges are expected as construction proceeds.
In 2009, the Georgia PSC approved inclusion of the Plant Vogtle Units 3 and 4 related CWIP accounts in rate base, and the State of Georgia enacted the Georgia Nuclear Energy Financing Act, which allows the Company to recover financing costs for nuclear construction projects certified by the Georgia PSC. Financing costs are recovered on all applicable certified costs through annual adjustments to the NCCR tariff by including the related CWIP accounts in rate base during the construction period. The Georgia PSC approved increases to the NCCR tariff of approximately $223 million, $35 million, $50 million, and $60 million, effective January 1, 2011, 2012, 2013, and 2014, respectively. On December 16, 2014, the Georgia PSC approved an increase to the NCCR tariff of approximately $27 million effective January 1, 2015.
In 2012, the Vogtle 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 Vogtle Owners are responsible for these costs under the terms of the Vogtle 3 and 4 Agreement. Also in 2012, the Company and the other Vogtle Owners filed suit against the Contractor in the U.S. District Court for the Southern District of Georgia seeking a declaratory judgment that the Vogtle Owners are not

responsible for these costs. In 2012, the Contractor also filed suit against the Company and the other Vogtle Owners in the U.S. District Court for the District of Columbia alleging the Vogtle Owners are responsible for these costs. In August 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 in September 2013. The portion of additional costs claimed by the Contractor in its initial complaint that would be attributable to the Company (based on the Company's ownership interest) is approximately $425 million (in 2008 dollars). The Contractor also asserted it is entitled to extensions of the guaranteed substantial completion dates of April 2016 and April 2017 for Plant Vogtle Units 3 and 4, respectively. On May 22, 2014, the Contractor filed an amended counterclaim to the suit pending in the U.S. District Court for the Southern District of Georgia alleging that (i) the design changes to the DCD imposed by the NRC delayed module production and the impacts to the Contractor are recoverable by the Contractor under the Vogtle 3 and 4 Agreement and (ii) the changes to the basemat rebar design

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required by the NRC caused additional costs and delays recoverable by the Contractor under the Vogtle 3 and 4 Agreement. The Contractor did not specify in its amended counterclaim the amounts relating to these new allegations; however, the Contractor has subsequently asserted related minimum damages (based on the Company's ownership interest) of $113 million. The Contractor may from time to time continue to assert that it is entitled to additional payments with respect to these allegations, any of which could be substantial. The Company has not agreed to the proposed cost or to any changes to the guaranteed substantial completion dates or that the Vogtle Owners have any responsibility for costs related to these issues. Litigation is ongoing and the Company intends to vigorously defend the positions of the Vogtle Owners. The Company also expects negotiations with the Contractor to continue with respect to cost and schedule during which negotiations the parties may reach a mutually acceptable compromise of their positions.

The Company is required to file semi-annual Vogtle Construction Monitoring (VCM) reports with the Georgia PSC by February 28 and August 31 each year. If the projected certified construction capital costs to be borne by the Company increase by 5% or the projected in-service dates are significantly extended, the Company is required to seek an amendment to the Plant Vogtle Units 3 and 4 certificate from the Georgia PSC. The Company's eighth VCM report filed in February 2013 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.

In September 2013, the Georgia PSC approved a stipulation (2013 Stipulation) entered into by the Company and the Georgia PSC staff to waive the requirement to amend the Plant Vogtle Units 3 and 4 certificate, until the completion of Plant Vogtle Unit 3, or earlier if deemed appropriate by the Georgia PSC and the Company. In accordance with the Georgia Integrated Resource Planning Act, any costs incurred by the Company in excess of the certified amount will be included in rate base, provided the Company shows the costs to be reasonable and prudent. In addition, financing costs on any construction-related costs in excess of the certified amount likely would be subject to recovery through AFUDC instead of the NCCR tariff.

The Georgia PSC has approved eleven VCM reports covering the periods through June 30, 2014, including construction capital costs incurred, which through that date totaled $2.8 billion.

On January 29, 2015, the Company announced that it was notified by the Contractor of the Contractor's revised forecast for completion of Plant Vogtle Units 3 and 4, which would incrementally delay the previously disclosed estimated in-service dates by 18 months (from the fourth quarter of 2017 to the second quarter of 2019 for Unit 3 and from the fourth quarter of 2018 to the second quarter of 2020 for Unit 4). The Company has not agreed to any changes to the guaranteed substantial completion dates of April 2016 and April 2017 for Plant Vogtle Units 3 and 4, respectively. The Company does not believe that the Contractor's revised forecast reflects all efforts that may be possible to mitigate the Contractor's delay.

In addition, the Company believes that, pursuant to the Vogtle 3 and 4 Agreement, the Contractor is responsible for the Contractor's costs related to the Contractor's delay (including any related construction and mitigation costs, which could be material) and that the Vogtle Owners are entitled to recover liquidated damages for the Contractor's delay beyond the guaranteed substantial completion dates of April 2016 and April 2017 for Plant Vogtle Units 3 and 4, respectively. Consistent with the Contractor's position in the pending litigation described above, the Company expects the Contractor to contest any claims for liquidated damages and to assert that the Vogtle Owners are responsible for additional costs related to the Contractor's delay.

On February 27, 2015, the Company filed its twelfth VCM report with the Georgia PSC covering the period from July 1 through December 31, 2014, which requests approval for an additional $0.2 billion of construction capital costs incurred during that period and reflects the Contractor's revised forecast for completion of Plant Vogtle Units 3 and 4 as well as additional estimated owner-related costs of approximately $10 million per month expected to result from the Contractor's proposed 18-month delay, including property taxes, oversight costs, compliance costs, and other operational readiness costs. No Contractor costs related to the Contractor's proposed 18-month delay are included in the twelfth VCM report. Additionally, while the Company has not agreed to any change to the guaranteed substantial completion dates, the twelfth VCM report includes a requested amendment to the Plant Vogtle Units 3 and 4 certificate to reflect the Contractor's revised forecast, to include the estimated owner's costs associated with the proposed 18-month Contractor delay, and to increase the estimated total in-service capital cost of Plant Vogtle Units 3 and 4 to $5.0 billion.

The Company will continue to incur financing costs of approximately $30 million per month until Plant Vogtle Units 3 and 4 are placed in service. The twelfth VCM report estimates total associated financing costs during the construction period to be approximately $2.5 billion.

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

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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 Vogtle Owners or the Contractor or to both.

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

Additional claims by the Contractor or the Company (on behalf of the Vogtle 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.

Nuclear Waste Fund Fee

In November 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. On March 18, 2014, the U.S. Court of Appeals for the District of Columbia Circuit denied the DOE's request for rehearing of the November 2013 panel decision ordering that the DOE propose the nuclear waste fund fee be changed to zero. The DOE formally set the fee to zero effective May 16, 2014. On June 17, 2014, the Georgia PSC approved the Company's request to credit customers the portion of fuel cost related to the nuclear waste fund fee. The nuclear waste fund rider to the Company's fuel tariffs became effective July 1, 2014.

4. JOINT OWNERSHIP AGREEMENTS

The Company and Alabama Power own equally all of the outstanding capital stock of SEGCO, which owns electric generating units with a total rated capacity of 1,020 MWs, as well as associated transmission facilities. The capacity of these units is sold equally to the Company and Alabama Power under a power contract. The Company and Alabama Power make payments sufficient to provide for the operating expenses, taxes, interest expense, and a ROE. The Company's share of purchased power totaled $84 million in 2014, $91 million in 2013, and $107 million in 2012 and is included in purchased power, affiliates in the statements of income. The Company accounts for SEGCO using the equity method.

The Company owns undivided interests in Plants Vogtle, Hatch, Wansley, and Scherer in varying amounts jointly with one or more of the following entities: OPC, MEAG Power, Dalton, Florida Power & Light Company, Jacksonville Electric Authority, and Gulf Power. Under these agreements, the Company has been contracted to operate and maintain the plants as agent for the co-owners and is jointly and severally liable for third party claims related to these plants. In addition, the Company jointly owns the Rocky Mountain pumped storage hydroelectric plant with OPC who is the operator of the plant. The Company and Duke Energy Florida, Inc. jointly own a combustion turbine unit (Intercession City) operated by Duke Energy Florida, Inc.

At December 31, 2014, the Company's percentage ownership and investment (exclusive of nuclear fuel) in jointly-owned facilities in commercial operation with the above entities were as follows:

Facility (Type)	Company Ownership	Plant in Service	Accumulated Depreciation	CWIP
		(in millions)		
Plant Vogtle (nuclear)				
Units 1 and 2	45.7%	$3,420	$2,059	$46
Plant Hatch (nuclear)	50.1	1,117	559	66
Plant Wansley (coal)	53.5	856	278	15

Plant Scherer (coal)				
Units 1 and 2	8.4	254	83	1
Unit 3	75.0	1,172	417	10
Rocky Mountain (pumped storage)	25.4	182	124	2
Intercession City (combustion-turbine)	33.3	14	5	—

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The Company's proportionate share of its plant operating expenses is included in the corresponding operating expenses in the statements of income and the Company is responsible for providing its own financing.
The Company also owns 45.7% of Plant Vogtle Units 3 and 4 that are currently under construction. See Note 3 under "Retail Regulatory Matters – Nuclear Construction" for additional information.

5. INCOME TAXES

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

Current and Deferred Income Taxes

Details of income tax provisions are as follows:

	2014	2013	2012
	(in millions)		
Federal –			
Current	$295	$277	$273
Deferred	366	374	370
	661	651	643
State –			
Current	82	(30)	38
Deferred	(14)	102	7
	68	72	45
Total	$729	$723	$688

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

	2014	2013
	(in millions)	
Deferred tax liabilities –		
Accelerated depreciation	$4,732	$4,479
Property basis differences	811	873
Employee benefit obligations	329	232
Under-recovered fuel costs	81	—
Premium on reacquired debt	66	73
Regulatory assets associated with employee benefit obligations	534	276
Asset retirement obligations	497	495
Other	160	168
Total	7,210	6,596
Deferred tax assets –		
Federal effect of state deferred taxes	148	159
Employee benefit obligations	642	388
Other property basis differences	86	93
Other deferred costs	86	84
Cost of removal obligations	11	17
State tax credit carry forward	170	118
Federal tax credit carry forward	5	3
Over-recovered fuel costs	—	22
Unbilled fuel revenue	46	53
Asset retirement obligations	497	495
Other	46	32
Total	1,737	1,464
Total deferred tax liabilities, net	5,473	5,132
Portion included in current assets/(liabilities), net	34	68
Accumulated deferred income taxes	$5,507	$5,200

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

At December 31, 2014, tax-related regulatory assets to be recovered from customers were $702 million. These assets are primarily attributable to tax benefits flowed through to customers in prior years, deferred taxes previously recognized at rates lower than the current enacted tax law, and taxes applicable to capitalized interest.

At December 31, 2014, tax-related regulatory liabilities to be credited to customers were $106 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 2011, the Company recorded a regulatory liability of $62 million related to a settlement with the Georgia Department of Revenue resolving claims for certain tax credits in 2005 through 2009. Amortization of the regulatory liability occurred ratably over the period from April 2012 through December 2013.

In accordance with regulatory requirements, deferred federal ITCs are amortized over the average 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 $10 million in 2014, $5 million in 2013, and $13 million in 2012. State ITCs are recognized in the period in which the credits are claimed on the state income tax return and totaled $34 million in 2014, $27 million in 2013, and $36 million in 2012. At December 31, 2014, the Company had $5 million in federal tax credit carry forwards that will expire by 2034 and $152 million in state ITC carry forwards that will expire between 2021 and 2025.

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

	2014	2013	2012
Federal statutory rate	35.0%	35.0%	35.0%
State income tax, net of federal deduction	2.2	2.5	1.6
Non-deductible book depreciation	1.3	1.3	1.2
AFUDC equity	(0.8)	(0.6)	(1.0)
Other	(0.7)	(0.4)	(0.1)
Effective income tax rate	37.0%	37.8%	36.7%

The decrease in the Company's 2014 effective tax rate is primarily the result of benefits related to emission allowances and state apportionment. The increase in the Company's 2013 effective tax rate is primarily the result of a decrease in state income tax credits and non-taxable AFUDC equity.
Unrecognized Tax Benefits
The Company had no unrecognized tax benefits during 2014. Changes in unrecognized tax benefits in prior years were as follows:

	2013	2012
	(in millions)	
Unrecognized tax benefits at beginning of year	$23	$47
Tax positions increase from current periods	—	3
Tax positions increase from prior periods	—	3
Tax positions decrease from prior periods	(23)	(19)
Reductions due to settlements	—	(8)
Reductions due to expired statute of limitations	—	(3)
Balance at end of year	$—	$23

The tax positions decrease from prior periods for 2013 and 2012 relate primarily to the tax accounting method change for repairs-generation assets and did not impact the effective tax rate. See "Tax Method of Accounting for Repairs" herein for additional information.
These amounts are presented on a gross basis without considering the related federal or state income tax impact.
The Company classifies interest on tax uncertainties as interest expense. Accrued interest for unrecognized tax benefits was immaterial for all periods presented. The Company did not accrue any penalties on uncertain tax positions.
The IRS has finalized its audits of Southern Company's consolidated federal income tax returns through 2012. Southern Company has filed its 2013 federal income tax return and has received a partial acceptance letter from the IRS; however, the IRS has not finalized its audit. Southern Company is a participant in the Compliance Assurance Process of the IRS. The audits for the Company's state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2008.
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, in April 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. In September 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 continues to review this guidance; however, these regulations are not expected to have a material impact on the Company's financial

statements.

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6. FINANCING
Securities Due Within One Year
A summary of scheduled maturities of long-term debt due within one year at December 31 was as follows:

	2014	2013
	(in millions)	
Senior notes	$1,050	$—
Pollution control revenue bonds	98	—
Capital lease	6	5
Total	$1,154	$5

Maturities through 2019 applicable to total long-term debt are as follows: $1.2 billion in 2015; $710 million in 2016; $457 million in 2017; $257 million in 2018; and $508 million in 2019.
Senior Notes
The Company did not issue any unsecured senior notes in 2014. At December 31, 2014 and 2013, the Company had $6.9 billion of senior notes outstanding. These senior notes are effectively subordinated to all secured debt of the Company, which aggregated $1.2 billion and $45 million at December 31, 2014 and 2013, respectively. As of December 31, 2014, the Company's secured debt included borrowings of $1.2 billion guaranteed by the DOE and capital leases. As of December 31, 2013, the Company's secured debt was related to capital lease obligations. See Note 7 for additional information.
See "DOE Loan Guarantee Borrowings" herein for additional information.
Pollution Control Revenue Bonds
Pollution control obligations represent loans to the Company from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control and solid waste disposal facilities. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. The amount of tax-exempt pollution control revenue bonds outstanding at December 31, 2014 and 2013 was $1.6 billion and $1.7 billion, respectively. Proceeds from certain issuances are restricted until qualifying expenditures are incurred.
In July 2014, the Company reoffered to the public $40 million aggregate principal amount of Development Authority of Monroe County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Scherer Project), First Series 2009, which had been previously purchased and held by the Company since 2010.
Bank Term Loans
In February 2014, the Company repaid three four-month floating rate bank loans in an aggregate principal amount of $400 million. At December 31, 2014, the Company had no bank term loans outstanding.
DOE Loan Guarantee Borrowings
Pursuant to the loan guarantee program established under Title XVII of the Energy Policy Act of 2005 (Title XVII Loan Guarantee Program), the Company and the DOE entered into a loan guarantee agreement (Loan Guarantee Agreement) on February 20, 2014, under which the DOE agreed to guarantee the obligations of the Company under a note purchase agreement (FFB Note Purchase Agreement) among the DOE, the Company, and the FFB and a related promissory note (FFB Promissory Note). The FFB Note Purchase Agreement and the FFB Promissory Note provide for a multi-advance term loan facility (FFB Credit Facility), under which the Company may make term loan borrowings through the FFB.
Proceeds of advances made under the FFB Credit Facility will be used to reimburse the Company for a portion of certain costs of construction relating to Plant Vogtle Units 3 and 4 that are eligible for financing under the Title XVII Loan Guarantee Program (Eligible Project Costs). Aggregate borrowings under the FFB Credit Facility may not exceed the lesser of (i) 70% of Eligible Project Costs or (ii) approximately $3.46 billion.
All borrowings under the FFB Credit Facility are full recourse to the Company, and the Company is obligated to reimburse the DOE for any payments the DOE is required to make to the FFB under the guarantee. The Company's

reimbursement obligations to the DOE are full recourse and secured by a first priority lien on (i) the Company's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4 (primarily the units under construction, the related real property, and any nuclear fuel loaded in the reactor core) and (ii) the Company's rights and obligations under the principal contracts relating to Plant Vogtle Units 3 and 4. There are no restrictions on the Company's ability to grant liens on other property.

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

On February 20, 2014, the Company made initial borrowings under the FFB Credit Facility in an aggregate principal amount of $1.0 billion. The interest rate applicable to $500 million of the initial advance under the FFB Credit Facility is 3.860% for an interest period that extends to 2044 and the interest rate applicable to the remaining $500 million is 3.488% for an interest period that extends to 2029, and is expected to be reset from time to time thereafter through 2044. In connection with its entry into the agreements with the DOE and the FFB, the Company incurred issuance costs of approximately $66 million, which will be amortized over the life of the borrowings under the FFB Credit Facility.

On December 11, 2014, the Company made additional borrowings under the FFB Credit Facility in an aggregate principal amount of $200 million. The interest rate applicable to the $200 million advance in December 2014 under the FFB Credit Facility is 3.002% for an interest period that extends to 2044.

Future advances are subject to satisfaction of customary conditions, as well as certification of compliance with the requirements of the Title XVII Loan Guarantee Program, including accuracy of project-related representations and warranties, delivery of updated project-related information, and evidence of compliance with the prevailing wage requirements of the Davis-Bacon Act of 1931, as amended, compliance with the Cargo Preference Act of 1954, and certification from the DOE's consulting engineer that proceeds of the advances are used to reimburse Eligible Project Costs.

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

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

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

Capital Leases

Assets acquired under capital leases are recorded in the balance sheets as utility plant in service, and the related obligations are classified as long-term debt. At December 31, 2014 and 2013, the Company had a capital lease asset for its corporate headquarters building of $61 million, with accumulated depreciation at December 31, 2014 and 2013 of $21 million and $16 million, respectively. At December 31, 2014 and 2013, the capitalized lease obligation was $40 million and $45 million, respectively, with an annual interest rate of 7.9% for both years. For ratemaking purposes, the Georgia PSC has allowed only the lease payments in cost of service. The difference between the accrued expense and the lease payments allowed for ratemaking purposes has been deferred and is being amortized to expense as ordered by the Georgia PSC. The annual expense incurred for all capital leases was not material for any year presented. See Note 7 under "Fuel and Purchased Power Agreements" for additional information on capital lease

PPAs that become effective in 2015.

Assets Subject to Lien

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

See "Capital Leases" above for information regarding certain assets held under capital leases.

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Outstanding Classes of Capital Stock
The Company currently has preferred stock, Class A preferred stock, preference stock, and common stock authorized. The Company has shares of its Class A preferred stock, preference stock, and common stock outstanding. The Company's Class A preferred stock ranks senior to the Company's preference stock and common stock with respect to payment of dividends and voluntary or involuntary dissolution. The Company's preference stock ranks senior to the common stock with respect to the payment of dividends and voluntary or involuntary dissolution. The outstanding series of the Class A preferred stock is subject to redemption at the option of the Company at any time at a redemption price equal to 100% of the par value. In addition, on or after October 1, 2017, the Company may redeem the outstanding series of the preference stock at a redemption price equal to 100% of the par value. With respect to any redemption of the preference stock prior to October 1, 2017, the redemption price includes a make-whole premium based on the present value of the liquidation amount and future dividends through the first par redemption date.
Dividend Restrictions
The Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital.
Bank Credit Arrangements
At December 31, 2014, committed credit arrangements with banks were as follows:

Expires[a]			
2016	2018	Total	Unused
(in millions)			
$150	$1,600	$1,750	$1,736

(a) No credit arrangements expire in 2015 or 2017.
Subject to applicable market conditions, the Company expects to renew its bank credit arrangements, as needed, prior to expiration. All of the bank credit arrangements require payment of commitment fees based on the unused portion of the commitments. Commitment fees average less than 1/4 of 1% for the Company.
The bank credit arrangements contain covenants that limit the Company's debt levels to 65% of total capitalization, as defined in the agreements. For purposes of these definitions, debt excludes certain hybrid securities.
A portion of the $1.7 billion unused credit with banks is allocated to provide liquidity support to the Company's variable rate pollution control revenue bonds and its commercial paper program. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2014 was $865 million. In addition, at December 31, 2014, the Company had $118 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months. As of December 31, 2014, $98 million of certain pollution control revenue bonds of the Company were reclassified to securities due within one year in anticipation of their redemption in connection with unit retirement decisions. See Note 3 under "Retail Regulatory Matters – Integrated Resource Plans" for additional information.
The Company makes short-term borrowings primarily through a commercial paper program that has the liquidity support of the Company's committed bank credit arrangements described above. The Company may also borrow through various other arrangements with banks. Commercial paper and short-term bank term loans are included in notes payable in the balance sheets.

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The Company had $156 million and $1.0 billion of short-term debt outstanding at December 31, 2014 and 2013, respectively. Details of short-term borrowings outstanding were as follows:

	Short-term Debt at the End of the Period		
	Amount Outstanding	Weighted Average Interest Rate	
	(in millions)		
December 31, 2014:			
Commercial paper	$156	0.3	%
December 31, 2013:			
Commercial paper	$647	0.2	%
Short-term bank debt	400	0.9	%
Total	$1,047	0.5	%

7. COMMITMENTS

Fuel and Purchased Power Agreements

To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement and delivery of fossil and nuclear fuel which are not recognized on the balance sheets. In 2014, 2013, and 2012, the Company incurred fuel expense of $2.5 billion, $2.3 billion, and $2.1 billion, respectively, the majority of which was purchased under long-term commitments. The Company expects that a substantial amount of its future fuel needs will continue to be purchased under long-term commitments.

The Company has commitments regarding a portion of a 5% interest in the original cost of Plant Vogtle Units 1 and 2 owned by MEAG Power that are in effect until the latter of the retirement of the plant or the latest stated maturity date of MEAG Power's bonds issued to finance such ownership interest. The payments for capacity are required whether or not any capacity is available. The energy cost is a function of each unit's variable operating costs. Portions of the capacity payments relate to costs in excess of MEAG Power's Plant Vogtle Unit 1 and 2 allowed investment for ratemaking purposes. The present value of these portions at the time of the disallowance was written off. Generally, the cost of such capacity and energy is included in purchased power, non-affiliates in the statements of income. Capacity payments totaled $19 million, $27 million, and $50 million in 2014, 2013, and 2012, respectively.

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The Company has also entered into various long-term PPAs, some of which are accounted for as capital or operating leases. Total capacity expense under PPAs accounted for as operating leases was $167 million, $162 million, and $169 million for 2014, 2013, and 2012, respectively. Estimated total long-term obligations at December 31, 2014 were as follows:

	Affiliate Capital Leases	Affiliate Operating Leases	Non-Affiliate Operating Leases [4]	Vogtle Units 1 and 2 Capacity Payments	Total ($)
	(in millions)				
2015	$22	$90	$114	$11	$237
2016	22	100	117	11	250
2017	23	71	146	10	250
2018	23	62	150	7	242
2019	23	63	152	6	244
2020 and thereafter	255	606	1,572	50	2,483
Total	$368	$992	$2,251	$95	$3,706
Less: amounts representing executory costs[1]	55				
Net minimum lease payments	313				
Less: amounts representing interest[2]	85				
Present value of net minimum lease payments[3]	$228				

(1) Executory costs such as taxes, maintenance, and insurance (including the estimated profit thereon) are estimated and included in total minimum lease payments.

(2) Amount necessary to reduce minimum lease payments to present value calculated at the Company's incremental borrowing rate at the inception of the leases.

(3) Once service commences under the PPAs beginning in 2015, the Company will recognize capital lease assets and capital lease obligations totaling $149 million, being the lesser of the estimated fair value of the lease property or the present value of the net minimum lease payments.

(4) A total of $1.1 billion of biomass PPAs included under the non-affiliate operating leases is contingent upon the counterparties meeting specified contract dates for commercial operation and may change as a result of regulatory action.

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and all of the other traditional operating companies and Southern Power. Under these agreements, each of the traditional operating companies and Southern Power may be jointly and severally liable. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the other traditional operating companies to ensure the Company will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power as a contracting party under these agreements.

Operating Leases

In addition to the PPA operating leases discussed above, the Company has other operating lease agreements with various terms and expiration dates. Total rent expense was $28 million for 2014, $32 million for 2013, and $34 million for 2012. The Company includes any step rents, fixed escalations, and lease concessions in its computation of minimum lease payments.

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As of December 31, 2014, estimated minimum lease payments under operating leases were as follows:

	Minimum Lease Payments		
	Railcars	Other	Total
	(in millions)		
2015	$18	$7	$25
2016	13	7	20
2017	9	7	16
2018	4	6	10
2019	1	4	5
2020 and thereafter	3	11	14
Total	$48	$42	$90

Railcar minimum lease payments are disclosed at 100% of railcar lease obligations; however, a portion of these obligations is shared with the joint owners of Plants Scherer and Wansley. A majority of the rental expenses related to the railcar leases are recoverable through the fuel cost recovery clause as ordered by the Georgia PSC and the remaining portion is recovered through base rates.

In addition to the above rental commitments, the Company has obligations upon expiration of certain railcar leases with respect to the residual value of the leased property. These leases have terms expiring through 2024 with maximum obligations under these leases of $32 million. At the termination of the leases, the lessee may either renew the lease, exercise its purchase option, or the property can be sold to a third party. The Company expects that the fair market value of the leased property would substantially reduce or eliminate the Company's payments under the residual value obligations.

Guarantees

Alabama Power has guaranteed the obligations of SEGCO for $25 million of pollution control revenue bonds issued in 2001, which mature in June 2019 and also $100 million of senior notes issued in November 2013, which mature in December 2018. The Company has agreed to reimburse Alabama Power for the pro rata portion of such obligations corresponding to the Company's then proportionate ownership of SEGCO's stock if Alabama Power is called upon to make such payment under its guarantee. See Note 4 for additional information.

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

As discussed earlier in this Note under "Operating Leases," the Company has entered into certain residual value guarantees related to railcar leases.

8. STOCK COMPENSATION

Stock Options

Southern Company provides non-qualified stock options through its Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. As of December 31, 2014, there were approximately 1,000 current and former employees of the Company 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. The Company generally recognizes stock option expense on a straight-line basis over the vesting period which equates to the requisite service period; however, for employees who are eligible for retirement, the total cost is expensed at the grant date. Options outstanding will expire no later than 10 years after the date of grant, unless terminated earlier by the Southern Company Board of Directors in accordance with the Omnibus Incentive Compensation Plan. Stock options held by employees of a company undergoing a change in control vest upon the change in control.

For the years ended December 31, 2014, 2013, and 2012, employees of the Company were granted stock options for 2,034,150 shares, 1,509,662 shares, and 1,269,725 shares, respectively. The weighted average grant-date fair value of stock options granted during 2014, 2013, and 2012, derived using the Black-Scholes stock option pricing model, was $2.20, $2.93, and $3.39, respectively.

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The compensation cost and tax benefits related to the grant of Southern Company stock options to the Company's employees and the exercise of stock options are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. No cash proceeds are received by the Company upon the exercise of stock options. The amounts were not material for any year presented. As of December 31, 2014, the amount of unrecognized compensation cost related to stock option awards not yet vested was immaterial.

The total intrinsic value of options exercised during the years ended December 31, 2014, 2013, and 2012 was $19 million, $16 million, and $34 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $7 million, $6 million, and $13 million for the years ended December 31, 2014, 2013, and 2012, respectively. As of December 31, 2014, the aggregate intrinsic value for the options outstanding and options exercisable was $73 million and $51 million, respectively.

Performance Shares

Southern Company provides performance share award units through its Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. The performance share units granted under the plan vest at the end of a three-year performance period which equates to the requisite service period. Employees that retire prior to the end of the three-year period receive a pro rata number of shares, issued at the end of the performance period, based on actual months of service prior to retirement. The value of the award units is based on Southern Company's total shareholder return (TSR) over the three-year performance period which measures Southern Company's relative performance against a group of industry peers. The performance shares are delivered in common stock following the end of the performance period based on Southern Company's actual TSR and may range from 0% to 200% of the original target performance share amount. Performance share units held by employees of a company undergoing a change in control vest upon the change in control.

For the years ended December 31, 2014, 2013, and 2012, employees of the Company were granted performance share units of 176,224, 161,240, and 152,812, respectively. The weighted average grant-date fair value of performance share units granted during 2014, 2013, and 2012, determined using a Monte Carlo simulation model to estimate the TSR of Southern Company's stock among the industry peers over the performance period, was $37.54, $40.50, and $41.99, respectively.

The Company recognizes compensation expense on a straight-line basis over the three-year performance period without remeasurement. Compensation expense for awards where the service condition is met is recognized regardless of the actual number of shares issued. For the years ended December 31, 2014, 2013, and 2012, total compensation cost for performance share units recognized in income was $6 million annually, with the related tax benefit of $2 million annually also recognized in income. The compensation cost and tax benefits related to the grant of Southern Company performance share units to the Company's employees are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. As of December 31, 2014, there was $7 million of total unrecognized compensation cost related to performance share award units that will be recognized over a weighted-average period of approximately 20 months.

9. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act (Act), the Company maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at Plant Hatch and Plant Vogtle Units 1 and 2. The Act provides funds up to $13.6 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $375 million by American Nuclear Insurers (ANI), with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. The Company could be assessed up to $127 million per incident for each licensed reactor it operates but not more than an aggregate of $19 million per incident to be paid in a calendar year for each reactor. Such maximum assessment, excluding any applicable state premium taxes, for the Company, based on its ownership and buyback interests in all licensed reactors, is $247 million, per incident, but not more than an aggregate of $37 million to be paid for each incident in any one year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due no later than September 10, 2018. See Note 4 for additional information on joint ownership agreements.

The Company is a member of Nuclear Electric Insurance Limited (NEIL), a mutual insurer established to provide property damage insurance in an amount up to $1.5 billion for members' operating nuclear generating facilities. Additionally, the Company has NEIL policies that currently provide decontamination, excess property insurance, and premature decommissioning coverage up to $1.25 billion for nuclear losses in excess of the $1.5 billion primary coverage. On April 1, 2014, NEIL introduced a new

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excess non-nuclear policy providing coverage up to $750 million for non-nuclear losses in excess of the $1.5 billion primary coverage.

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

A builders' risk property insurance policy has been purchased from NEIL for the construction of Plant Vogtle Units 3 and 4. This policy provides the Owners up to $2.75 billion for accidental property damage occurring during construction.

Under each of the NEIL policies, members are subject to assessments each year if losses exceed the accumulated funds available to the insurer. The current maximum annual assessments for the Company under the NEIL policies would be $72 million.

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

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

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

10. FAIR VALUE MEASUREMENTS

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

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

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

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NOTES (continued)
Georgia Power Company 2014 Annual Report

As of December 31, 2014, 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, 2014:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in millions)			
Assets:				
Energy-related derivatives	$—	$7	$—	$7
Interest rate derivatives	—	6	—	6
Nuclear decommissioning trusts:[a]				
Domestic equity	180	2	—	182
Foreign equity	—	121	—	121
U.S. Treasury and government agency securities	—	96	—	96
Municipal bonds	—	62	—	62
Corporate bonds	—	188	—	188
Mortgage and asset backed securities	—	121	—	121
Other	11	8	—	19
Total	$191	$611	$—	$802
Liabilities:				
Energy-related derivatives	$—	$27	$—	$27
Interest rate derivatives	—	14	—	14
Total	$—	$41	$—	$41

(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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NOTES (continued)
Georgia Power Company 2014 Annual Report

As of December 31, 2013, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2013:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in millions)			
Assets:				
Energy-related derivatives	$—	$5	$—	$5
Nuclear decommissioning trusts:[(a)]				
Domestic equity	197	1	—	198
Foreign equity	—	131	—	131
U.S. Treasury and government agency securities	—	79	—	79
Municipal bonds	—	64	—	64
Corporate bonds	—	140	—	140
Mortgage and asset backed securities	—	114	—	114
Other	—	24	—	24
Total	$197	$558	$—	$755
Liabilities:				
Energy-related derivatives	$—	$21	$—	$21

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

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

NOTES (continued)
Georgia Power Company 2014 Annual Report

As of December 31, 2014 and 2013, 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, 2014:	(in millions)			
Nuclear decommissioning trusts:				
Foreign equity fund	$ 121	None	Monthly	5 days
Other — commingled funds	8	None	Daily	Not applicable
Other — money market funds	11	None	Daily	Not applicable
As of December 31, 2013:				
Nuclear decommissioning trusts:				
Foreign equity fund	$ 131	None	Daily	5 days
Corporate bonds — commingled funds	8	None	Daily	Not applicable
Other — commingled funds	24	None	Daily	Not applicable

The NRC requires licensees of commissioned nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. The foreign equity fund in the nuclear decommissioning trusts seeks to provide long-term capital appreciation. In pursuing this investment objective, the foreign equity fund primarily invests in a diversified portfolio of equity securities of foreign companies, including those in emerging markets. These equity securities may include, but are not limited to, common stocks, preferred stocks, real estate investment trusts, convertible securities, depositary receipts, including American depositary receipts, European depositary receipts, and global depositary receipts; and rights and warrants to buy common stocks. The Company may withdraw all or a portion of its investment on the last business day of each month subject to a minimum withdrawal of $1 million, provided that a minimum investment of $10 million remains. If notices of withdrawal exceed 20% of the aggregate value of the foreign equity fund, then the foreign equity fund's board may refuse to permit the withdrawal of all such investments and may scale down the amounts to be withdrawn pro rata and may further determine that any withdrawal that has been postponed will have priority on the subsequent withdrawal date.

The other-commingled funds and other-money market funds in the nuclear decommissioning trusts are invested primarily in a diversified portfolio of high quality, short-term, liquid debt securities. The funds represent the cash collateral received under the Funds' managers' securities lending program and/or the excess cash held within each separate investment account. The primary objective of the funds is to provide a high level of current income consistent with stability of principal and liquidity. The funds invest primarily in, but not limited to, commercial paper, floating and variable rate demand notes, debt securities issued or guaranteed by the U.S. government or its agencies or instrumentalities, time deposits, repurchase agreements, municipal obligations, notes, and other high-quality short-term liquid debt securities that mature in 90 days or less. Redemptions are available on a same day basis up to the full amount of the investment in the funds. See Note 1 under "Nuclear Decommissioning" for additional information.

As of December 31, 2014 and 2013, 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:		
2014	$9,797	$10,552
2013	$8,593	$8,782

The fair values are determined using Level 2 measurements and are based on quoted market prices for the same or similar issues or on current rates offered to the Company.

11. DERIVATIVES

The Company is exposed to market risks, primarily commodity price risk and interest rate risk. To manage the volatility attributable to these exposures, the Company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company’s policies in areas such as counterparty

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exposure and risk management practices. The Company’s policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a gross basis. See Note 10 for additional information. In the statements of cash flows, the cash impacts of settled energy-related and interest rate derivatives are recorded as operating activities.

Energy-Related Derivatives

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, the Company has limited exposure to market volatility in commodity fuel prices and prices of electricity. The Company manages a fuel-hedging program, implemented per the guidelines of the Georgia PSC, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility.

To mitigate residual risks relative to movements in gas prices, the Company may enter into fixed-price contracts for natural gas purchases; however, a significant portion of contracts are priced at market.

Energy-related derivative contracts are accounted for in one of two methods:

- Regulatory Hedges – Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the Company’s fuel-hedging program, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the fuel cost recovery mechanism.
- Not Designated – Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

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

At December 31, 2014, the net volume of energy-related derivative contracts for natural gas positions totaled 46 million mmBtu, all of which expire by 2017, which is the longest hedge date.

In addition to the volume discussed above, the Company enters into physical natural gas supply contracts that provide the option to sell back excess gas due to operational constraints. The expected volume of natural gas subject to such a feature is 4 million mmBtu for the Company.

Interest Rate Derivatives

The Company may also enter into interest rate derivatives to hedge exposure to changes in interest rates. 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 fixed rate securities are accounted for as fair value hedges, where the derivatives' fair value gains and losses and the hedged items' fair value gains and losses attributable to interest rate risk are both recorded directly to earnings, providing an offset, with any differences representing ineffectiveness.

At December 31, 2014, the following interest rate derivatives were outstanding:

NOTES (continued)
Georgia Power Company 2014 Annual Report

	Notional Amount (in millions)	Interest Rate Received	Weighted Average Interest Rate Paid	Hedge Maturity Date	Fair Value Gain (Loss) December 31, 2014 (in millions)
Cash Flow Hedges of Forecasted Debt					
	$ 350	3-month LIBOR	2.57%	May 2025	$(6)
	350	3-month LIBOR	2.57%	November 2025	(2)
Cash Flow Hedges of Existing Debt					
	250	3-month LIBOR + 0.32%	0.75%	March 2016	—
	200	3-month LIBOR + 0.40%	1.01%	August 2016	—
Fair value hedges of existing debt					
	250	5.40%	3-month LIBOR + 4.02%	June 2018	(1)
	200	4.25%	3-month LIBOR + 2.46%	December 2019	—
Total	$ 1,600				$(9)

The estimated pre-tax losses that will be reclassified from accumulated OCI to interest expense for the 12-month period ending December 31, 2015 are immaterial. The Company has deferred gains and losses related to interest rate derivative settlements of cash flow hedges that are expected to be amortized into earnings through 2037.

NOTES (continued)
Georgia Power Company 2014 Annual Report

Derivative Financial Statement Presentation and Amounts
At December 31, 2014 and 2013, 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	2014	2013	Liability Derivatives Balance Sheet Location	2014	2013
		(in millions)			(in millions)	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	$6	$3	Liabilities from risk management activities	$23	$13
	Other deferred charges and assets	1	2	Other deferred credits and liabilities	4	8
Total derivatives designated as hedging instruments for regulatory purposes		$7	$5		$27	$21
Derivatives designated as hedging instruments in cash flow and fair value hedges						
Interest rate derivatives:	Other current assets	$5	$—	Liabilities from risk management activities	$9	$—
	Other deferred charges and assets	1	—	Other deferred credits and liabilities	5	—
Total derivatives designated as hedging instruments in cash flow and fair value hedges		$6	$—		$14	$—
Total		$13	$5		$41	$21

Energy-related derivatives not designated as hedging instruments were immaterial on the balance sheets for 2014 and 2013.
The derivative contracts of the Company are not subject to master netting arrangements or similar agreements and are reported gross on the Company's financial statements. Some of these energy-related and interest rate derivative contracts may contain certain provisions that permit intra-contract netting of derivative receivables and payables for routine billing and offsets related to events of default and settlements. Amounts related to energy-related derivative contracts and interest rate derivative contracts at December 31, 2014 and 2013 are presented in the following tables.

Fair Value

Assets	2014	2013	Liabilities	2014	2013
	(in millions)			(in millions)	
Energy-related derivatives presented in the Balance Sheet [(a)]	$7	$5	Energy-related derivatives presented in the Balance Sheet [(a)]	$27	$21
Gross amounts not offset in the Balance Sheet [(b)]	(7)	(5)	Gross amounts not offset in the Balance Sheet [(b)]	(7)	(5)
Net energy-related derivative assets	$—	$—	Net energy-related derivative liabilities	$20	$16

Interest rate derivatives presented in the Balance Sheet [a]	$6	$—	Interest rate derivatives presented in the Balance Sheet [a]	$14	$—
Gross amounts not offset in the Balance Sheet [b]	(6)	—	Gross amounts not offset in the Balance Sheet [b]	(6)	—
Net interest rate derivative assets	$—	$—	Net interest rate derivative liabilities	$8	$—

(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.

NOTES (continued)
Georgia Power Company 2014 Annual Report

At December 31, 2014 and 2013, 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	2014	2013	Unrealized Gains Balance Sheet Location	2014	2013
		(in millions)			(in millions)	
Energy-related derivatives:	Other regulatory assets, current	$(23)	$(13)	Other regulatory liabilities, current	$6	$3
	Other regulatory assets, deferred	(4)	(8)	Other deferred credits and liabilities	1	2
Total energy-related derivative gains (losses)		$(27)	$(21)		$7	$5

For the year ended December 31, 2014, the pre-tax effect of interest rate derivatives designated as fair value hedging instruments on the statement of income was immaterial on a gross basis for the Company. Furthermore, the pre-tax effect of interest rate derivatives designated as fair value hedging instruments on the Company's statement of income was offset by changes to the carrying value of the long-term debt. The gains and losses related to interest rate derivative settlements of fair value hedges are recorded directly to earnings.

The pre-tax effects of interest rate derivatives designated as cash flow hedging instruments include $8 million of losses recognized in OCI for the year ended December 31, 2014 and amounts reclassified from accumulated OCI into earnings that were immaterial for all years presented.

There was no material ineffectiveness recorded in earnings for any period presented. The pre-tax effect of energy-related derivatives not designated as hedging instruments on the statements of income was immaterial for all years presented.

Contingent Features

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain affiliated companies. At December 31, 2014, the Company's collateral posted with its derivative counterparties was immaterial.

At December 31, 2014, the fair value of derivative liabilities with contingent features was $4 million. However, because of joint and several liability features underlying these derivatives, the maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $54 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.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P or with counterparties who have posted collateral to cover potential credit exposure. The Company has also established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk. Therefore, the Company does not anticipate a material adverse effect on the financial statements as a result of counterparty nonperformance.

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12. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)
Summarized quarterly financial information for 2014 and 2013 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred and Preference Stock
	(in millions)		
March 2014	$2,269	$516	$266
June 2014	2,186	572	311
September 2014	2,631	920	525
December 2014	1,902	288	123
March 2013	$1,882	$412	$197
June 2013	2,042	552	282
September 2013	2,484	872	487
December 2013	1,866	404	208

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

SELECTED FINANCIAL AND OPERATING DATA 2010-2014
Georgia Power Company 2014 Annual Report

	2014	2013	2012	2011	2010
Operating Revenues (in millions)	$8,988	$8,274	$7,998	$8,800	$8,349
Net Income After Dividends on Preferred and Preference Stock (in millions)	$1,225	$1,174	$1,168	$1,145	$950
Cash Dividends on Common Stock (in millions)	$954	$907	$983	$1,096	$820
Return on Average Common Equity (percent)	12.24	12.45	12.76	12.89	11.42
Total Assets (in millions)	$31,030	$28,907	$28,803	$27,151	$25,914
Gross Property Additions (in millions)	$2,146	$1,906	$1,838	$1,981	$2,401
Capitalization (in millions):					
Common stock equity	$10,421	$9,591	$9,273	$9,023	$8,741
Preferred and preference stock	266	266	266	266	266
Long-term debt	8,683	8,633	7,994	8,018	7,931
Total (excluding amounts due within one year)	$19,370	$18,490	$17,533	$17,307	$16,938
Capitalization Ratios (percent):					
Common stock equity	53.8	51.9	52.9	52.1	51.6
Preferred and preference stock	1.4	1.4	1.5	1.5	1.6
Long-term debt	44.8	46.7	45.6	46.4	46.8
Total (excluding amounts due within one year)	100.0	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	2,102,673	2,080,358	2,062,040	2,047,390	2,049,770
Commercial*	301,246	298,420	296,397	295,288	295,347
Industrial*	9,132	9,136	9,143	9,134	8,929
Other	9,003	8,623	7,724	7,521	7,309
Total	2,422,054	2,396,537	2,375,304	2,359,333	2,361,355
Employees (year-end)	7,909	7,886	8,094	8,310	8,330

* A reclassification of customers from commercial to industrial is reflected for years 2010-2013 to be consistent with the rate structure approved by the Georgia PSC. The impact to operating revenues, kilowatt-hour sales, and average revenue per kilowatt-hour by class is not material.

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SELECTED FINANCIAL AND OPERATING DATA 2010-2014 (continued)
Georgia Power Company 2014 Annual Report

	2014	2013	2012	2011	2010
Operating Revenues (in millions):					
Residential	$3,350	$3,058	$2,986	$3,241	$3,072
Commercial	3,271	3,077	2,965	3,217	3,011
Industrial	1,525	1,391	1,322	1,547	1,441
Other	94	94	89	94	84
Total retail	8,240	7,620	7,362	8,099	7,608
Wholesale — non-affiliates	335	281	281	341	380
Wholesale — affiliates	42	20	20	32	53
Total revenues from sales of electricity	8,617	7,921	7,663	8,472	8,041
Other revenues	371	353	335	328	308
Total	$8,988	$8,274	$7,998	$8,800	$8,349
Kilowatt-Hour Sales (in millions):					
Residential	27,132	25,479	25,742	27,223	29,433
Commercial	32,426	31,984	32,270	32,900	33,855
Industrial	23,549	23,087	23,089	23,519	23,209
Other	633	630	641	657	663
Total retail	83,740	81,180	81,742	84,299	87,160
Wholesale — non-affiliates	4,323	3,029	2,934	3,904	4,662
Wholesale — affiliates	1,117	496	600	626	1,000
Total	89,180	84,705	85,276	88,829	92,822
Average Revenue Per Kilowatt-Hour (cents):					
Residential	12.35	12.00	11.60	11.91	10.44
Commercial	10.09	9.62	9.19	9.78	8.89
Industrial	6.48	6.03	5.73	6.58	6.21
Total retail	9.84	9.39	9.01	9.61	8.73
Wholesale	6.93	8.54	8.52	8.23	7.65
Total sales	9.66	9.35	8.99	9.54	8.66
Residential Average Annual Kilowatt-Hour Use Per Customer	12,969	12,293	12,509	13,288	14,367
Residential Average Annual Revenue Per Customer	$1,605	$1,475	$1,451	$1,582	$1,499
Plant Nameplate Capacity Ratings (year-end) (megawatts)	17,593	17,586	17,984	16,588	15,992
Maximum Peak-Hour Demand (megawatts):					
Winter	16,308	12,767	14,104	14,800	15,614
Summer	15,777	15,228	16,440	16,941	17,152
Annual Load Factor (percent)	61.2	63.5	59.1	59.5	60.9
Plant Availability (percent)*:					
Fossil-steam	86.3	87.1	90.3	88.6	88.6
Nuclear	90.8	91.8	94.1	92.2	94.0
Source of Energy Supply (percent):					
Coal	30.9	26.4	26.6	44.4	51.8
Nuclear	16.7	17.7	18.3	16.6	16.4
Hydro	1.3	2.0	0.7	1.1	1.4
Oil and gas	26.3	29.6	22.0	8.9	8.0

Purchased power —					
From non-affiliates	3.8	3.3	6.8	6.1	5.2
From affiliates	21.0	21.0	25.6	22.9	17.2
Total	100.0	100.0	100.0	100.0	100.0

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

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GULF POWER COMPANY
FINANCIAL SECTION

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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Gulf Power Company 2014 Annual Report
The management of Gulf Power Company (the Company) is responsible for establishing and maintaining an adequate system of internal control over financial reporting as required by the Sarbanes-Oxley Act of 2002 and as defined in Exchange Act Rule 13a-15(f). A control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met.
Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2014.
/s/ S. W. Connally, Jr.
S. W. Connally, Jr.
President and Chief Executive Officer
/s/ Richard S. Teel
Richard S. Teel
Vice President and Chief Financial Officer
March 2, 2015

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM
To the Board of Directors of
Gulf Power Company

We have audited the accompanying balance sheets and statements of capitalization of Gulf Power Company (the Company) (a wholly owned subsidiary of The Southern Company) as of December 31, 2014 and 2013, and the related statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2014. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements (pages II-307 to II-345) present fairly, in all material respects, the financial position of Gulf Power Company as of December 31, 2014 and 2013, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America.
/s/ Deloitte & Touche LLP
Atlanta, Georgia
March 2, 2015

DEFINITIONS

Term	Meaning
AFUDC	Allowance for funds used during construction
Alabama Power	Alabama Power Company
ASC	Accounting Standards Codification
CCR	Coal combustion residuals
Clean Air Act	Clean Air Act Amendments of 1990
CO_2	Carbon dioxide
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
GAAP	Generally accepted accounting principles
Georgia Power	Georgia Power Company
IRS	Internal Revenue Service
ITC	Investment tax credit
KWH	Kilowatt-hour
Mississippi Power	Mississippi Power Company
mmBtu	Million British thermal units
Moody's	Moody's Investors Service, Inc.
MW	Megawatt
OCI	Other comprehensive income
power pool	The operating arrangement whereby the integrated generating resources of the traditional operating companies and Southern Power Company are subject to joint commitment and dispatch in order to serve their combined load obligations
PPA	Power purchase agreement
PSC	Public Service Commission
ROE	Return on equity
S&P	Standard and Poor's Rating Services, a division of The McGraw Hill Companies, Inc.
scrubber	Flue gas desulfurization system
SCS	Southern Company Services, Inc. (the Southern Company system service company)
SEC	U.S. Securities and Exchange Commission
Southern Company system	The Southern Company, the traditional operating companies, Southern Power, Southern Electric Generating Company, Southern Nuclear, SCS, SouthernLINC Wireless, and other subsidiaries
SouthernLINC Wireless	Southern Communications Services, Inc.
Southern Nuclear	Southern Nuclear Operating Company, Inc.
Southern Power	Southern Power Company and its subsidiaries
traditional operating companies	Alabama Power, Georgia Power, Gulf Power Company, and Mississippi Power

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MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Gulf Power Company 2014 Annual Report
OVERVIEW
Business Activities
Gulf Power Company (the Company) operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located in northwest Florida and to wholesale customers in the Southeast.
Many factors affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the ability to maintain a constructive regulatory environment, to maintain and grow energy sales, 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, restoration following major storms, and fuel. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future.
In December 2013, the Florida PSC voted to approve the settlement agreement (Settlement Agreement) among the Company and all of the intervenors to the docketed proceeding with respect to the Company's request to increase retail base rates. Under the terms of the Settlement Agreement, the Company (1) increased base rates designed to produce an additional $35 million in annual revenues effective January 2014 and subsequently increased base rates designed to produce an additional $20 million in annual revenues effective January 2015; (2) continued its current authorized retail ROE midpoint (10.25%) and range (9.25% – 11.25%); (3) may reduce depreciation expense and record a regulatory asset that will be included as an offset to the other cost of removal regulatory liability in an aggregate amount up to $62.5 million between January 2014 and June 2017; and (4) will accrue a return similar to AFUDC on certain transmission system upgrades placed into service after January 2014 until the next base rate adjustment date or January 1, 2017, whichever comes first. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Retail Base Rate Case" herein for additional details of the Settlement Agreement.
Key Performance Indicators
The Company continues to focus on several key performance indicators including customer satisfaction, plant availability, system reliability, and net income after dividends on preference stock. The Company's financial success is directly tied to customer satisfaction. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys to evaluate the Company's results and generally targets the top quartile of these surveys in measuring performance, which the Company achieved in 2014.
Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. The Company's 2014 Peak Season EFOR of 0.98% was better than the target. Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on historical performance. The Company's performance for 2014 was better than the target for these transmission and distribution reliability measures.
The Company uses net income after dividends on preference stock as the primary measure of the Company's financial performance. In 2014, the Company achieved its targeted net income after dividends on preference stock. See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance.
Earnings
The Company's 2014 net income after dividends on preference stock was $140.2 million, representing a $15.8 million, or 12.7%, increase over the previous year. The increase was primarily due to higher retail revenues, partially offset by higher other operations and maintenance expenses as compared to the corresponding period in 2013.
In 2013, net income after dividends on preference stock was $124.4 million, representing a $1.5 million, or 1.2%, decrease from the previous year. The decrease was primarily due to an increase in depreciation and dividends on preference stock, partially offset by decreases in other operations and maintenance expenses and interest expense as

compared to the corresponding period in 2012.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Gulf Power Company 2014 Annual Report

RESULTS OF OPERATIONS

A condensed statement of income follows:

	Amount	Increase (Decrease) from Prior Year	
	2014	2014	2013
	(in millions)		
Operating revenues	$1,590.5	$150.2	$0.6
Fuel	604.6	71.8	(12.1)
Purchased power	107.2	21.9	11.2
Other operations and maintenance	341.2	31.4	(4.3)
Depreciation and amortization	145.0	(4.0)	8.0
Taxes other than income taxes	111.2	12.8	1.0
Total operating expenses	1,309.2	133.9	3.8
Operating income	281.3	16.3	(3.2)
Total other income and (expense)	(44.0)	9.2	3.7
Income taxes	88.1	8.4	0.5
Net income	149.2	17.1	—
Dividends on preference stock	9.0	1.3	1.5
Net income after dividends on preference stock	$140.2	$15.8	$(1.5)

Operating Revenues

Operating revenues for 2014 were $1.59 billion, reflecting an increase of $150.2 million from 2013. The following table summarizes the significant changes in operating revenues for the past two years:

	Amount	
	2014	2013
	(in millions)	
Retail — prior year	$1,170.0	$1,144.5
Estimated change resulting from –		
Rates and pricing	47.1	0.1
Sales growth (decline)	8.2	(1.4)
Weather	9.4	(0.3)
Fuel and other cost recovery	31.8	27.1
Retail — current year	1,266.5	1,170.0
Wholesale revenues –		
Non-affiliates	129.2	109.4
Affiliates	130.1	99.6
Total wholesale revenues	259.3	209.0
Other operating revenues	64.7	61.3
Total operating revenues	$1,590.5	$1,440.3
Percent change	10.4 %	— %

In 2014, retail revenues increased $96.5 million, or 8.3%, when compared to 2013 primarily as a result of higher fuel cost recovery revenues and higher revenues resulting from an increase in retail base rates effective January 2014, as approved by the Florida PSC. In 2013, retail revenues increased $25.5 million, or 2.2%, when compared to 2012 primarily as a result of higher fuel revenues and energy conservation cost recovery revenues. The increase in fuel revenues was partially offset by a payment received during 2013 pursuant to the resolution of a coal contract dispute. See "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales growth (or decline) and weather.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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In 2014, revenues associated with changes in rates and pricing included higher revenues due to an increase in retail base rates and revenues associated with higher rates under the Company's environmental cost recovery clause. In 2013, revenues associated with changes in rates and pricing were relatively flat as a result of higher revenues due to increases in retail base rates, partially offset by lower rates under the Company's energy conservation cost recovery clause and the environmental cost recovery clause. Annually, the Company petitions the Florida PSC for recovery of projected costs, including any true-up amount from prior periods, and approved rates are implemented each January. The recovery provisions include related expenses and a return on average net investment.

Fuel and other cost recovery provisions include fuel expenses, the energy component of purchased power costs, purchased power capacity costs, and the difference between projected and actual costs and revenues related to energy conservation and environmental compliance. Annually, the Company petitions the Florida PSC for recovery of projected fuel and purchased power costs, including any true-up amount from prior periods, and approved rates are implemented each January. The recovery provisions generally equal the related expenses and have no material effect on earnings.

See Note 1 to the financial statements under "Revenues" and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information regarding the Company's retail base rate case and cost recovery clauses, including the Company's fuel cost recovery, purchased power capacity recovery, environmental cost recovery, and energy conservation cost recovery clauses.

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

	2014	2013	2012
	(in millions)		
Capacity and other	$65.1	$64.0	$68.2
Energy	64.1	45.4	38.7
Total non-affiliated	$129.2	$109.4	$106.9

Wholesale revenues from sales to non-affiliates consist of long-term sales agreements to other utilities in Florida and Georgia and short-term opportunity sales. Capacity revenues from long-term sales agreements represent the greatest contribution to net income. The energy is generally sold at variable cost. Short-term opportunity sales are made at market-based rates that generally provide a margin above the Company's variable cost of energy. Wholesale energy revenues from sales to non-affiliates will vary depending on fuel prices, the market prices of wholesale energy compared to the cost of the Company's and the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation. See FUTURE EARNINGS POTENTIAL – "General" for additional information.

In 2014, wholesale revenues from sales to non-affiliates increased $19.8 million, or 18.1%, as compared to the prior year primarily due to a 43.7% increase in KWH sales as a result of lower-priced energy supply alternatives from the Southern Company system's resources and fewer planned outages at Plant Scherer Unit 3 partially offset by a 1.9% decrease in the price of energy sold to non-affiliates due to the lower cost of fuel per KWH generated. In 2013, wholesale revenues from sales to non-affiliates increased $2.5 million, or 2.3%, as compared to the prior year primarily due to an 18.9% increase in KWH sales as a result of more energy scheduled by wholesale customers to serve their loads. This increase was partially offset by a 6.2% decrease in capacity revenues reflecting contractual reductions for changes in environmental costs.

Wholesale revenues from sales to affiliated companies will vary depending on demand and the availability and cost of generating resources at each company. These affiliate sales are made in accordance with the Intercompany Interchange Contract (IIC), as approved by the FERC. These transactions do not have a significant impact on earnings since the revenue related to these energy sales generally offsets the cost of energy sold. In 2014, wholesale revenues from sales to affiliates increased $30.5 million, or 30.7%, as compared to the prior year primarily due to a 24.5% increase in the price of energy sold to affiliates due to higher marginal generation costs and a 5.0% increase in KWH sales as a result of an increase of the Company's generation dispatched to serve affiliated companies' higher weather-related energy demand primarily in the first and third quarters of 2014. In 2013, wholesale revenues from sales to affiliates decreased $24.1 million, or 19.5%, as compared to the prior year primarily due to lower energy revenues related to a 28.4% decrease in KWH sales that resulted from less Company generation being dispatched to serve affiliated companies' demand. This decrease in 2013 was partially offset by a 12.7% increase in the price of energy sold to affiliates in 2013.

Other operating revenues increased $3.4 million, or 5.5%, in 2014 as compared to the prior year primarily due to a $4.5 million increase in franchise fees due to increased retail revenues, partially offset by a $2.3 million decrease in revenues from other energy services. In 2013, other operating revenues decreased $3.4 million, or 5.3%, as compared to the prior year primarily due to a $5.4 million decrease in revenues from other energy services, partially offset by a $1.9 million increase in transmission

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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revenues. Franchise fees have no impact on net income. Revenues from other energy services did not have a material effect on net income since they were generally offset by associated expenses.

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2014 and the percent change from the prior year were as follows:

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2014	2014	2013	2014	2013
	(in millions)				
Residential	5,363	5.4 %	0.7 %	1.3 %	0.5 %
Commercial	3,838	0.7	(1.3)	0.1	(0.4)
Industrial	1,849	8.8	(1.4)	8.8	(1.4)
Other	25	20.5	(17.1)	20.5	(17.1)
Total retail	11,075	4.3	(0.4)	2.1 %	(0.2)%
Wholesale					
Non-affiliates	1,670	43.7	18.9		
Affiliates	3,284	5.0	(28.4)		
Total wholesale	4,954	15.5	(19.8)		
Total energy sales	16,029	7.5 %	(6.9)%		

Changes in retail energy sales are generally the result of changes in electricity usage by customers, changes in weather, and changes in the number of customers.

Residential KWH sales increased in 2014 compared to 2013 primarily due to colder weather in the first quarter of 2014 and customer growth. Residential KWH sales increased in 2013 compared to 2012 primarily due to customer growth.

Commercial KWH sales increased in 2014 compared to 2013 primarily due to colder weather in the first quarter of 2014 and customer growth, partially offset by a decline in weather-adjusted use per customer. Commercial KWH sales decreased in 2013 compared to 2012 primarily due to milder weather in 2013 compared to 2012 and a decline in weather-adjusted use per customer, partially offset by customer growth.

Industrial KWH sales increased in 2014 compared to 2013 primarily due to decreased customer co-generation and changes in customers' operations. Industrial KWH sales decreased in 2013 compared to 2012 primarily due to changes in customers' operations.

See "Operating Revenues" above for a discussion of significant changes in wholesale sales to non-affiliates and affiliated companies.

Fuel and Purchased Power Expenses

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

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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Details of the Company's generation and purchased power were as follows:

	2014	2013	2012
Total generation (millions of KWHs)	11,109	9,216	9,648
Total purchased power (millions of KWHs)	5,547	6,298	6,952
Sources of generation (percent) –			
Coal	67	61	60
Gas	33	39	40
Cost of fuel, generated (cents per net KWH) –			
Coal[(a)]	4.03	4.12	4.42
Gas	3.93	3.95	3.96
Average cost of fuel, generated (cents per net KWH)[(a)]	3.99	4.05	4.23
Average cost of purchased power (cents per net KWH)[(b)]	4.83	3.88	3.03

(a) 2013 cost of coal includes the effect of a payment received pursuant to the resolution of a coal contract dispute.
(b) Average cost of purchased power includes fuel purchased by the Company for tolling agreements where power is generated by the provider.

In 2014, total fuel and purchased power expenses were $711.8 million, an increase of $93.7 million, or 15.2%, from the prior year costs. Total fuel and purchased power expenses for 2013 included a 2013 payment received pursuant to the resolution of a coal contract dispute. Excluding the payment, the higher volume of KWHs generated and purchased increased expenses $54.9 million primarily due to increased Company owned generation dispatched to serve higher Southern Company system demand as a result of colder weather in the first quarter and warmer weather in the third quarter 2014. The increased expenses also included an $18.3 million increase due to a higher average cost of fuel and purchased power.

In 2013, total fuel and purchased power expenses were $618.1 million, a decrease of $0.9 million, or 0.2%, from the prior year costs. The decrease in fuel and purchased power expenses was due to a $37.3 million decrease in the volume of KWHs generated and purchased, partially offset by a $36.4 million increase in the average cost of fuel and purchased power which included a payment received during 2013 pursuant to the resolution of a coal contract dispute. Excluding the payment, the average cost of fuel and purchased power increased $57.0 million.

Fuel and purchased power transactions do not have a significant impact on earnings since energy and capacity expenses are generally offset by energy and capacity revenues through the Company's fuel cost, purchased power capacity recovery clauses, and long-term wholesale contracts. See Note 3 to the financial statements under "Retail Regulatory Matters – Cost Recovery Clauses – Retail Fuel Cost Recovery" and " – Purchased Power Capacity Recovery" for additional information.

Fuel

Fuel expense was $604.6 million in 2014, an increase of $71.8 million, or 13.5%, from the prior year costs. The increase was primarily due to a 20.5% higher volume of KWHs generated primarily due to increased generation dispatched to serve higher Southern Company system loads due to colder weather in the first quarter 2014 and warmer weather in the third quarter 2014. The fuel expense for 2013 included a 2013 payment received pursuant to the resolution of a coal contract dispute. Excluding the payment, the average cost of fuel per KWH generated decreased 6.8%. In 2013, fuel expense was $532.8 million, a decrease of $12.1 million, or 2.2%, from the prior year costs. The decrease was primarily due to a 4.3% decrease in the average cost of fuel per KWH generated which included a 2013 payment received pursuant to the resolution of a coal contract dispute. Excluding the payment, the average cost of fuel per KWH generated increased 1.2%.

Purchased Power – Non-Affiliates

Purchased power expense from non-affiliates was $82.0 million in 2014, an increase of $29.6 million, or 56.3%, from the prior year. The increase was due to a 37.3% increase in the average cost per KWH purchased, which included a $28.4 million increase in capacity costs associated with a scheduled price increase for an existing PPA, partially offset by the expiration of another PPA. This increase was partially offset by a 16.3% decrease in the volume of KWHs purchased due to colder regional weather conditions in the first quarter 2014 which limited the availability of market resources. In 2013, purchased power expense from non-affiliates was $52.4 million, an increase of $1.0 million, or 2.0%, from the prior year. The increase was due to a 31.5% increase in the average cost per KWH purchased, partially offset by a 13.8% decrease in the volume of KWHs purchased.

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

Purchased Power – Affiliates

Purchased power expense from affiliates was $25.2 million in 2014, a decrease of $7.7 million, or 23.1%, from the prior year. The decrease was primarily due to a 43.3% decrease in the average cost per KWH purchased, which included a $13.5 million reduction in capacity costs primarily associated with the expiration of an existing PPA. This decrease was partially offset by a 33.2% increase in the volume of KWHs purchased primarily due to higher planned outages for the Company's generating units in the fourth quarter 2014. In 2013, purchased power expense from affiliates was $32.9 million, an increase of $10.2 million, or 44.9%, from the prior year. The increase was primarily due to a 93.4% increase in the volume of KWHs purchased, partially offset by a 30.2% decrease in the average cost per KWH purchased.

Energy purchases from affiliates will vary depending on demand and the availability and cost of generating resources at each company within the Southern Company system. These purchases are made in accordance with the IIC or other contractual agreements, all as approved by the FERC.

Other Operations and Maintenance Expenses

In 2014, other operations and maintenance expenses increased $31.4 million, or 10.1%, compared to the prior year primarily due to increases in routine and planned maintenance expenses at generation, transmission and distribution facilities.

In 2013, other operations and maintenance expenses decreased $4.3 million, or 1.4%, compared to the prior year primarily due to decreases of $14.4 million in routine and planned maintenance expenses at generation facilities related to decreases in scheduled outages and cost containment efforts in 2013 and $4.9 million in other energy services expenses, partially offset by increases of $5.1 million in pension and other benefit-related expenses, $4.9 million in transmission service related to a third party PPA, $2.2 million in distribution system maintenance primarily due to increased vegetation management and $2.1 million in marketing incentive programs. Expenses from other energy services did not have a significant impact on earnings since they were generally offset by associated revenues. Expenses from transmission service did not have a significant impact on earnings since this expense was offset by purchased power capacity revenues through the Company's purchased power capacity recovery clause. Expenses from marketing incentive programs did not have a significant impact on earnings since the expense was offset by energy conservation revenues through the Company's energy conservation cost recovery clause. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Cost Recovery Clauses," and Notes 1 and 3 to the financial statements under "Affiliate Transactions" and "Cost Recovery Clauses," respectively, for additional information.

Depreciation and Amortization

Depreciation and amortization decreased $4.0 million, or 2.7%, in 2014 compared to the prior year. As authorized by the Florida PSC in the Settlement Agreement, the Company recorded an $8.4 million reduction in depreciation expense in 2014. This decrease was partially offset by increases of $4.4 million in depreciation and amortization primarily attributable to property additions at generation, transmission, and distribution facilities. In 2013, depreciation and amortization increased $8.0 million, or 5.7%, compared to the prior year primarily attributable to equipment replacements completed on Plant Crist Unit 7 and other additions to transmission and distribution facilities. See Note 3 to the financial statements under "Retail Regulatory Matters – Retail Base Rate Case" for additional information.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $12.8 million, or 13.0%, in 2014 compared to the prior year primarily due to increases of $4.4 million in franchise fees and $4.0 million in gross receipts taxes as a result of higher retail revenues as well as a $2.7 million increase in property taxes. In 2013, taxes other than income taxes increased $1.0 million, or 1.1%, compared to the prior year primarily due to a $2.8 million increase in property taxes, partially offset by decreases of $0.7 million in gross receipts taxes, $0.7 million in payroll taxes, and $0.4 million in franchise fees. Gross receipts taxes and franchise fees have no impact on net income.

Allowance for Equity Funds Used During Construction

AFUDC equity increased $5.6 million, or 86.4%, in 2014 compared to the prior year primarily due to increased construction projects related to environmental control projects at generation facilities and transmission projects. In 2013, AFUDC equity increased $1.2 million, or 23.5%, compared to the prior year primarily due to increased construction projects related to environmental control projects at generation facilities. See Note 1 to the financial statements under "Allowance for Funds Used During Construction" for additional information.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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Interest Expense, Net of Amounts Capitalized
Interest expense, net of amounts capitalized decreased $2.8 million, or 5.0%, in 2014 compared to the prior year primarily due to an increase in capitalization of AFUDC debt related to the construction of environmental control projects and lower interest rates on pollution control bonds, offset by increases in long term debt resulting from the issuance of additional senior notes in 2014. In 2013, interest expense, net of amounts capitalized decreased $4.2 million, or 7.0%, compared to the prior year primarily due to lower interest rates on pollution control bonds, senior notes, and customer deposits.
Income Taxes
Income taxes increased $8.4 million, or 10.5%, in 2014 compared to the prior year primarily due to higher pre-tax earnings. See Note 5 to the financial statements under "Effective Tax Rate" for additional information.
Effects of Inflation
The Company is subject to rate regulation that is generally based on the recovery of historical and projected costs. The effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. Any adverse effect of inflation on the Company's results of operations has not been substantial in recent years.
FUTURE EARNINGS POTENTIAL
General
The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located in northwest Florida and to wholesale customers in the Southeast. Prices for electricity provided by the Company to retail customers are set by the Florida PSC under cost-based regulatory principles. Prices for wholesale electricity sales, interconnecting transmission lines, and the exchange of electric power are regulated by the FERC. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Electric Utility Regulation" herein and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information about regulatory matters.
The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the Company's ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently-incurred costs during a time of increasing costs. Future earnings in the near term will depend, in part, upon maintaining and growing sales which are subject to a number of factors. These factors include weather, competition, energy conservation practiced by customers, the price of electricity, the price elasticity of demand, the rate of economic growth or decline in the Company's service territory, and the successful remarketing of wholesale capacity as current contracts expire. Changes in regional and global economic conditions may impact sales for the Company, as the pace of the economic recovery remains uncertain. The timing and extent of the economic recovery will impact growth and may impact future earnings.
The Company's wholesale business consists of two types of agreements. The first type, referred to as requirements service, provides that the Company serves the customer's capacity and energy requirements from other Company resources. The second type, referred to as a unit sale, is a wholesale customer purchase from a dedicated generating plant unit where a portion of that unit is reserved for the customer. These agreements are associated with the Company's co-ownership of a unit with Georgia Power at Plant Scherer and consist of both capacity and energy sales. Capacity revenues represent the majority of the Company's wholesale earnings. The Company currently has long-term sales agreements for 100% of the Company’s ownership of that unit for 2015 and 41% for the next five years. These capacity revenues represented 82% of total wholesale capacity revenues for 2014. The Company is actively pursuing replacement wholesale contracts but the expiration of current contracts could have a material negative impact on the Company's earnings. In the event some portion of the Company's ownership in Plant Scherer is not subject to a

replacement long-term wholesale contract, the proportionate amount of the unit may be sold into the power pool or into the wholesale market.
Environmental Matters
Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be recovered in retail rates or through long-term wholesale agreements on a timely basis or through market-based contracts. The State of Florida has statutory provisions that allow a utility to petition the Florida PSC for recovery of prudent environmental compliance costs that are not being recovered through base rates or any other recovery mechanism. The Company's current long-term wholesale agreements contain provisions that permit charging the customer with costs incurred as a

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result of changes in environmental laws and regulations. The full impact of any such regulatory or legislative changes cannot be determined at this time. 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 or long-term wholesale agreements could contribute to reduced demand for electricity as well as impact the cost competitiveness of wholesale capacity, which could negatively affect results of operations, cash flows, and financial condition. See Note 3 to the financial statements under "Environmental Matters" and "Retail Regulatory Matters – Cost Recovery Clauses – Environmental Cost Recovery" for additional information including a discussion on the State of Florida's statutory provisions on environmental cost recovery.

Subsequent to December 31, 2014, the Company announced plans to retire its coal-fired generation at Plant Smith Units 1 and 2 (357 MWs) by March 31, 2016. The plant will continue to operate and produce electricity with its other generating units on site. The cost to comply with environmental regulations imposed by the EPA led to the decision to close these units. The retirement of these units is not expected to have a material impact on the Company's financial statements. The Company expects to recover through its rates the remaining book value of the retired units and certain costs associated with the retirements; however, recovery will be considered by the Florida PSC in future rate proceedings. The net book value of these units at December 31, 2014 was approximately $80 million.

The Company has also determined it is not economical to add the environmental controls at Plant Scholz necessary to comply with the Mercury and Air Toxics Standards (MATS) rule and that coal-fired generation at Plant Scholz (92 MWs) will cease by April 2015. The plant is scheduled to be fully depreciated by April 2015.

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 Georgia Power alleging violations of the New Source Review provisions of the Clean Air Act at certain coal-fired electric generating units, including a unit co-owned by the Company. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. See Note 3 to the financial statements under "Environmental Matters – New Source Review Actions" for additional information. The ultimate outcome of these matters cannot be determined at this time.

Environmental Statutes and Regulations

General

The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; the Endangered Species Act; and related federal and state regulations. Compliance with these environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. Through 2014, the Company had invested approximately $1.8 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $227 million, $143 million, and $70 million for 2014, 2013, and 2012, respectively. The Company expects that capital expenditures to comply with environmental statutes and regulations will total approximately $204 million from 2015 through 2017, with annual totals of approximately $127 million, $39 million, and $38 million for 2015, 2016, and 2017, respectively. These estimated expenditures do not include any potential compliance costs that may arise from the EPA's proposed rules that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. See "Global Climate Issues" for additional information.

The Company's ultimate environmental compliance strategy, including potential unit retirement and replacement decisions and future environmental capital expenditures will be affected by the final requirements of new or revised environmental regulations and regulations relating to global climate change that are promulgated, including the proposed environmental regulations described below; the outcome of any legal challenges to the environmental rules; the cost, availability, and existing inventory of emissions allowances; and the Company's fuel mix. Compliance costs may arise from existing unit retirements, installation of additional environmental controls, upgrades to the transmission system, closure and monitoring of CCR facilities, and adding or changing fuel sources for certain existing units. The ultimate outcome of these matters cannot be determined at this time.

Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Company. Since 1990, the Company has spent approximately $1.4 billion in reducing and monitoring emissions pursuant to the Clean Air

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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Act. Additional controls are currently planned or under consideration to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements.

In 2012, the EPA finalized the 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, up to April 16, 2016 for affected units for which extensions have been granted. On November 25, 2014, the U.S. Supreme Court granted a petition for review of the final MATS rule.

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 2012, the EPA published its final determination of nonattainment areas based on the 2008 eight-hour ozone NAAQS. All areas within the Company's service territory have achieved attainment of this standard. On December 17, 2014, the EPA published a proposed rule to further reduce the current eight-hour ozone standard. The EPA is required by federal court order to complete this rulemaking by October 1, 2015. Finalization of a lower eight-hour ozone standard could result in the designation of new ozone nonattainment areas within the Company's service territory.

The EPA regulates fine particulate matter concentrations on an annual and 24-hour average basis. All areas within the Company's service territory have achieved attainment with the 1997 and 2006 particulate matter NAAQS. In 2012, the EPA issued a final rule that increases the stringency of the annual fine particulate matter standard. The EPA promulgated final designations for the 2012 annual standard on December 18, 2014, and no new nonattainment areas were designated within the Company's service territory. The EPA has, however, deferred designation decisions for certain areas in Florida, so future nonattainment designations in these areas are possible.

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

The Company's service territory is subject to the requirements of the Cross State Air Pollution Rule (CSAPR). CSAPR is an emissions trading program that limits SO_2 and nitrogen oxide emissions from power plants in 28 states in two phases, with Phase I beginning in 2015 and Phase II beginning in 2017. In 2012, the U.S. Court of Appeals for the District of Columbia Circuit vacated CSAPR in its entirety, but on April 29, 2014, the U.S. Supreme Court overturned that decision and remanded the case back to the U.S. Court of Appeals for the District of Columbia Circuit for further proceedings. The U.S. Court of Appeals for the District of Columbia Circuit granted the EPA's motion to lift the stay of the rule, and the first phase of CSAPR took effect on January 1, 2015.

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, including fossil fuel-fired generating facilities, built between 1962 and 1977 and any additional emissions reductions necessary for each designated area to achieve reasonable progress toward the natural visibility conditions goal by 2018 and for each 10-year period thereafter.

In 2012, the EPA published proposed revisions to the New Source Performance Standard (NSPS) for Stationary Combustion Turbines (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.

In February 2013, the EPA proposed a rule that would require certain states to revise the provisions of their State Implementation Plans (SIPs) relating to the regulation of excess emissions at industrial facilities, including fossil fuel-fired generating facilities, during periods of startup, shut-down, or malfunction (SSM). The EPA proposed to supplement the 2013 proposed rule on September 17, 2014, making it more stringent. The EPA has entered into a settlement agreement requiring it to finalize the proposed rule by May 22, 2015. The proposed rule would require states subject to the rule (including Florida, Georgia, and Mississippi) to revise their SSM provisions within 18 months after issuance of the final rule.

The Company has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the current and proposed environmental requirements discussed above. As part of this strategy, the Company has developed a compliance plan for the MATS rule which includes reliance on existing emission control technologies, the use of existing or additional natural gas capability, and unit retirements. Additionally, certain transmission system upgrades are required. The impacts of the eight-hour ozone, fine particulate matter and SO_2 NAAQS, CSAPR, CAVR, the MATS rule, the NSPS for CTs, and the SSM rule on the Company cannot be determined at this time and will depend on the specific provisions of

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the proposed and final rules, the resolution of pending and future legal challenges, and/or the development and implementation of rules at the state level. These regulations could result in significant additional compliance costs that could affect future unit retirement and replacement decisions and results of operations, cash flows, and financial condition.

Water Quality

The EPA's final rule establishing standards for reducing effects on fish and other aquatic life caused by new and existing cooling water intake structures at existing power plants and manufacturing facilities became effective on October 14, 2014. The effect of this final rule will depend on the results of additional studies and implementation of the rule by regulators based on site-specific factors. The ultimate impact of this rule will also depend on the outcome of ongoing legal challenges and cannot be determined at this time.

In June 2013, the EPA published a proposed rule which requested comments on a range of potential regulatory options for addressing revised technology-based limits for certain wastestreams from steam electric power plants and best management practices for CCR surface impoundments. The EPA has entered into a consent decree requiring it to finalize revisions to the steam electric effluent guidelines by September 30, 2015. The ultimate impact of the rule will also depend on the specific technology requirements of the final rule and the outcome of any legal challenges and cannot be determined at this time.

On April 21, 2014, the EPA and the U.S. Army Corps of Engineers jointly published a proposed rule to revise the regulatory definition of waters of the U.S. for all Clean Water Act (CWA) programs, which would significantly expand the scope of federal jurisdiction under the CWA. In addition, the rule as proposed could have significant impacts on economic development projects which could affect customer demand growth. The ultimate impact of the proposed rule will depend on the specific requirements of the final rule and the outcome of any legal challenges and cannot be determined at this time. If finalized as proposed, this rule could significantly increase permitting and regulatory requirements and costs associated with the siting of new facilities and the installation, expansion, and maintenance of transmission and distribution lines.

In addition, numeric nutrient water quality standards promulgated by the State of Florida to limit the amount of nitrogen and phosphorous allowed in state waters are in effect for the State's streams and estuaries. The impact of these standards will depend on further regulatory action in connection with their site-specific implementation through the State of Florida's National Pollutant Discharge Elimination System permitting program and Total Maximum Daily Load restoration program and cannot be determined at this time.

These proposed and final water quality 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.

Coal Combustion Residuals

The Company currently manages CCR at onsite storage units consisting of landfills and surface impoundments (CCR Units) at three electric generating plants in Florida and is part owner of units at generating plants located in Mississippi and Georgia operated by the respective unit's co-owner. In addition to on-site storage, the Company sells a portion of its CCR to third parties for beneficial reuse. Individual states regulate CCR and the States of Florida, Georgia, and Mississippi each have their own regulatory requirements. The Company has an inspection program in place to assist in maintaining the integrity of its coal ash surface impoundments.

On December 19, 2014, the EPA issued the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule), but has not yet published it in the Federal Register. The CCR Rule will regulate the disposal of CCR, including coal ash and gypsum, as non-hazardous solid waste in CCR Units at active generating power plants. The CCR Rule does not mandate closure of CCR Units, but includes minimum criteria for active and inactive surface impoundments containing CCR and liquids, lateral expansions of existing units, and active landfills. Failure to meet the minimum criteria can result in the mandated closure of a CCR Unit. Although the EPA does not require individual states to adopt the final criteria, states have the option to incorporate the federal criteria into their state solid waste management plans in order to regulate CCR in a manner consistent with federal standards. The EPA's final rule continues to exclude the beneficial use of CCR from regulation.

The ultimate impact of the CCR Rule cannot be determined at this time and will depend on the Company's ongoing review of the CCR Rule, the results of initial and ongoing minimum criteria assessments, and the outcome of legal challenges. The cost and timing of potential ash pond closure and ongoing monitoring activities that may be required in connection with the CCR Rule is also uncertain; however, the Company has developed a preliminary nominal dollar estimate of costs associated with closure and groundwater monitoring of ash ponds in place of approximately $62 million and ongoing post-closure care of approximately $11 million. The Company has previously recorded asset retirement obligations (ARO) associated with ash ponds of $6 million, or $11 million on a nominal dollar basis, based on existing state requirements. During 2015, the Company will record AROs for any incremental estimated closure costs resulting from acceleration in the timing of any currently planned closures and for differences

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between existing state requirements and the requirements of the CCR Rule. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates.

Environmental Remediation

The Company must comply with other environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company could incur substantial costs to clean up properties. The Company conducts studies to determine the extent of any required cleanup and has recognized in its financial statements the costs to clean up known impacted sites. Included in this amount are costs associated with remediation of the Company's substation sites. These projects have been approved by the Florida PSC for recovery through the environmental cost recovery clause; therefore, these liabilities have no impact to the Company's net income. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Note 3 to the financial statements under "Environmental Matters – Environmental Remediation" for additional information.

Global Climate Issues

In 2014, the EPA published three sets of proposed standards that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. On January 8, 2014, the EPA published proposed standards for new units, and, on June 18, 2014, the EPA published proposed standards governing existing units, known as the Clean Power Plan, and separate standards governing CO_2 emissions from modified and reconstructed units. The EPA's proposed Clean Power Plan establishes guidelines for states to develop plans to address CO_2 emissions from existing fossil fuel-fired electric generating units. The EPA's proposed guidelines establish state-specific interim and final CO_2 emission rate goals to be achieved between 2020 and 2029 and in 2030 and thereafter. The proposed guidelines and standards could result in operational restrictions and material compliance costs, including capital expenditures, which could affect future unit retirement and replacement decisions. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates or through market-based contracts.

The Southern Company system filed comments on the EPA's proposed Clean Power Plan on December 1, 2014. These comments addressed legal and technical issues in addition to providing a preliminary estimated cost of complying with the proposed guidelines utilizing one of the EPA's compliance scenarios. Costs associated with this proposal could be significant to the utility industry and the Southern Company system. However, the ultimate financial and operational impact of the proposed Clean Power Plan on the Southern Company system cannot be determined at this time and will depend upon numerous known and unknown factors. Some of the unknown factors include: the structure, timing, and content of the EPA's final guidelines; individual state implementation of these guidelines, including the potential that state plans impose different standards; additional rulemaking activities in response to legal challenges and related court decisions; the impact of future changes in generation and emissions-related technology and costs; the impact of future decisions regarding unit retirement and replacement, including the type and amount of any such replacement capacity; and the time periods over which compliance will be required.

Over the past several years, the U.S. Congress has also 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.

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 Company's 2013 greenhouse gas emissions were approximately 8 million metric tons of CO_2 equivalent. The preliminary estimate of the Company's 2014 greenhouse gas emissions on the same basis is approximately 10 million metric tons of CO_2 equivalent. The level of greenhouse gas emissions from year to year will depend on the level of generation, the mix of fuel sources, and other factors.

Retail Regulatory Matters

The Company's rates and charges for service to retail customers are subject to the regulatory oversight of the Florida PSC. The Company's rates are a combination of base rates and several separate cost recovery clauses for specific categories of costs. These separate cost recovery clauses address such items as fuel and purchased energy costs, purchased power capacity costs, energy conservation and demand side management programs, and the costs of compliance with environmental laws and regulations. Costs not addressed through one of the specific cost recovery clauses are recovered through the Company's base rates. See Note 3 to the financial statements under "Retail Regulatory Matters" for additional information.

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Retail Base Rate Case
In December 2013, the Florida PSC voted to approve the Settlement Agreement among the Company and all of the intervenors to the docketed proceeding with respect to the Company's request to increase retail base rates. Under the terms of the Settlement Agreement, the Company (1) increased base rates designed to produce an additional $35 million in annual revenues effective January 2014 and subsequently increased base rates designed to produce an additional $20 million in annual revenues effective January 2015; (2) continued its current authorized retail ROE midpoint (10.25%) and range (9.25% – 11.25%); and (3) will accrue a return similar to AFUDC on certain transmission system upgrades placed into service after January 2014 until the next base rate adjustment date or January 1, 2017, whichever comes first.
The Settlement Agreement also provides that the Company may reduce depreciation expense and record a regulatory asset that will be included as an offset to the other cost of removal regulatory liability in an aggregate amount up to $62.5 million between January 2014 and June 2017. In any given month, such depreciation expense reduction may not exceed the amount necessary for the 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 the Company's next base rate case or next depreciation and dismantlement study proceeding, whichever comes first. The Company recognized an $8.4 million reduction in depreciation expense in 2014.
Cost Recovery Clauses
On October 22, 2014, the Florida PSC approved the Company's annual rate clause request for its fuel, purchased power capacity, environmental, and energy conservation cost recovery factors for 2015. The net effect of the approved changes is an expected $41.2 million increase in annual revenue for 2015. The increased revenues will not have a significant impact on net income since most of the revenues will be offset by expenses.
Revenues for all cost recovery clauses, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor for fuel and purchased power will have no significant effect on the Company's revenues or net income, but will affect annual cash flow. The recovery provisions for environmental compliance and energy conservation include related expenses and a return on net average investment. See Note 1 to the financial statements under "Revenues" for additional information.
Income Tax Matters
Bonus Depreciation
On December 19, 2014, the Tax Increase Prevention Act of 2014 (TIPA) was signed into law. The TIPA retroactively extended several tax credits through 2014 and extended 50% bonus depreciation for property placed in service in 2014 (and for certain long-term production-period projects to be placed in service in 2015). The extension of 50% bonus depreciation had a positive impact on the Company's cash flows and, combined with bonus depreciation allowed in 2014 under the American Taxpayer Relief Act of 2012, resulted in approximately $25 million of positive cash flows for the 2014 tax year. The estimated cash flow benefit of bonus depreciation related to TIPA is expected to be approximately $65 million to $70 million for the 2015 tax year.
Other Matters
The Company is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of business. The Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements, such as air quality and water standards, has occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by CO_2 and other emissions, CCR, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements, management

does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements. See Note 3 to the financial statements for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

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ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

The Company prepares its 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 the Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has reviewed and discussed the following critical accounting policies and estimates with the Audit Committee of Southern Company's Board of Directors.

Electric Utility Regulation

The Company is subject to retail regulation by the Florida PSC. The Florida PSC sets the rates the Company is permitted to charge customers based on allowable costs. The Company is also subject to cost-based regulation by the FERC with respect to wholesale transmission rates. As a result, the Company applies accounting standards which require the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of the accounting standards has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the Company; therefore, the accounting estimates inherent in specific costs such as depreciation, AROs, and pension and postretirement benefits have less of a direct impact on the Company's results of operations and financial condition than they would on a non-regulated company.

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

Contingent Obligations

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

Pension and Other Postretirement Benefits

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

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

For purposes of its December 31, 2014 measurement date, the Company adopted new mortality tables for its pension plans and retiree life and medical plans, which reflect increased life expectancies in the U.S. The adoption of new mortality tables increased

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the projected benefit obligations for the Company's pension plans and other postretirement benefit plans by approximately $29.6 million and $2.6 million, respectively. The adoption of new mortality tables will increase net periodic costs related to the Company's pension plans and other postretirement benefit plans in 2015 by $3.9 million and $0.1 million, respectively.

A 25 basis point change in any significant assumption (discount rate, salaries, or long-term return on plan assets) would result in a $1.6 million or less change in total annual benefit expense and a $22.0 million or less change in projected obligations.

Recently Issued Accounting Standards

On May 28, 2014, the Financial Accounting Standards Board issued ASC 606, Revenue from Contracts with Customers. ASC 606 revises the accounting for revenue recognition and is effective for fiscal years beginning after December 15, 2016. The Company continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2014. The Company's cash requirements primarily consist of funding ongoing operations, common stock dividends, capital expenditures, and debt maturities. Capital expenditures and other investing activities include investments to meet projected long-term demand requirements, to comply with environmental regulations, and for restoration following major storms. Operating cash flows provide a substantial portion of the Company's cash needs. For the three-year period from 2015 through 2017, the Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. Projected capital expenditures in that period are primarily to maintain existing generation facilities, to add environmental equipment for existing generating units, and to expand and improve transmission and distribution facilities. The Company plans to finance future cash needs in excess of its operating cash flows primarily through debt and equity issuances and through equity contributions from Southern Company. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements to meet future capital and liquidity needs. See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

The Company's investments in the qualified pension plan increased in value as of December 31, 2014 as compared to December 31, 2013. In December 2014, the Company voluntarily contributed $30.0 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2015. See Note 2 to the financial statements under "Pension Plans" for additional information.

Net cash provided from operating activities totaled $343.1 million in 2014, an increase of $13.4 million from 2013, primarily due to changes in cash flows related to clause recovery and a decrease in fossil fuel stock. This increase was partially offset by decreases in cash flows associated with pension, post-retirement and other employee benefits, and deferred income taxes.

In 2013, net cash provided from operating activities totaled $329.7 million, a decrease of $89.5 million from 2012, primarily due to decreases in deferred income taxes related to bonus depreciation and lower recovery of fuel costs which moved from an over recovered to an under recovered position. These decreases were partially offset by increases in cash flow related to reductions in fossil fuel stock.

Net cash used for investing activities totaled $357.7 million, $306.6 million, and $348.6 million for 2014, 2013, and 2012, respectively. The changes in cash used for investing activities were primarily due to gross property additions to utility plant of $360.9 million, $304.8 million, and $325.2 million for 2014, 2013, and 2012, respectively. Funds for the Company's property additions were provided by operating activities, capital contributions, and other financing activities.

Net cash provided from financing activities totaled $31.5 million for 2014. Net cash used for financing activities totaled $33.6 million and $55.8 million for 2013 and 2012, respectively. The $65.1 million increase in cash from financing activities in 2014 was primarily due to the issuance of long-term debt and common stock, partially offset by the payment of common stock dividends, the redemption of long-term debt and a decrease to notes payable. The decreases of cash used in 2013 and 2012 were primarily for the payment of common stock dividends and redemptions of long-term debt, partially offset by issuances of stock to Southern Company and 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 2014 included increases of $231.3 million in property, plant, and equipment, primarily due to additions in generation, transmission, and distribution facilities, $211.4 million in long-term debt, $75.6 million in other regulatory assets, deferred, related to pension and other postretirement benefits, $55.7 million in other regulatory assets primarily related to an increase in contract hedges, $50.0 million in common stock issued to Southern Company, and $44.4 million in

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employee benefit obligations as a result of changes in the actuarial assumptions. Decreases included $75.0 million in securities due within one year.

The Company's ratio of common equity to total capitalization, including short-term debt, was 44.6% in 2014 and 44.9% in 2013. See Note 6 to the financial statements for additional information.

Sources of Capital

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

Security issuances are subject to annual regulatory approval by the Florida PSC pursuant to its rules and regulations. Additionally, with respect to the public offering of securities, the Company files registration statements with the SEC under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the Florida PSC, as well as the amounts, if any, registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

The Company obtains financing separately without credit support from any affiliate. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of the Company are not commingled with funds of any other company in the Southern Company system.

The Company's current liabilities frequently exceed current assets because of the continued use of short-term debt as a funding source to meet scheduled maturities of long-term debt, as well as cash needs, which can fluctuate significantly due to the seasonality of the business. The Company has substantial cash flow from operating activities and access to the capital markets and financial institutions to meet short-term liquidity needs, including its commercial paper program which is supported by bank credit facilities.

At December 31, 2014, the Company had approximately $38.6 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2014 were as follows:

Expires					Executable Term-Loans		Due Within One Year	
2015	2016	2017	Total	Unused	One Year	Two Years	Term Out	No Term Out
(in millions)								
$80	$165	$30	$275	$275	$50	$—	$50	$30

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

Most of these bank credit 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 Company. Such cross default provisions to other indebtedness would trigger an event of default if the Company defaulted on indebtedness or guarantee obligations over a specified threshold. The Company is currently in compliance with all such covenants. None of the bank credit arrangements contain material adverse change clauses at the time of borrowings. Subject to applicable market conditions, the Company expects to renew its bank credit arrangements as needed, prior to expiration.

Most of the unused credit arrangements with banks is allocated to provide liquidity support to the Company's variable rate pollution control revenue bonds and commercial paper program. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2014 was approximately $69.3 million. At December 31, 2014, the Company had $78.0 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months.

The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of the Company and the other traditional operating companies. Proceeds from such issuances for the benefit of the Company are loaned directly to the Company. The obligations of each company under these arrangements are several and there is no cross-affiliate credit support.

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Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period		Short-term Debt During the Period [a]		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		(in millions)		(in millions)
December 31, 2014:					
Commercial paper	$110	0.3 %	$85	0.2 %	$145
December 31, 2013:					
Commercial paper	$136	0.2 %	$92	0.2 %	$173
Short-term bank debt	—	N/A	11	1.2 %	125
Total	$136	0.2 %	$103	0.3 %	
December 31, 2012:					
Commercial paper	$124	0.3 %	$69	0.3 %	$124

(a) Average and maximum amounts are based upon daily balances during the year.

The Company believes the need for working capital can be adequately met by utilizing the commercial paper program, lines of credit, and cash.

Financing Activities

In January 2014, the Company issued 500,000 shares of common stock to Southern Company and realized proceeds of $50.0 million. The proceeds were used to repay a portion of the Company's short-term debt and for other general corporate purposes, including the Company's continuous construction program.

In April 2014, the Company executed a loan agreement with Mississippi Business Finance Corporation (MBFC) related to MBFC's issuance of $29.075 million aggregate principal amount of Pollution Control Revenue Refunding Bonds, First Series 2014 (Gulf Power Company Project) due April 1, 2044 for the benefit of the Company. The proceeds were used to redeem $29.075 million aggregate principal amount of MBFC Pollution Control Revenue Refunding Bonds, Series 2003 (Gulf Power Company Project).

In June 2014, the Company reoffered to the public $13 million aggregate principal amount of MBFC Solid Waste Disposal Facilities Revenue Refunding Bonds, Series 2012 (Gulf Power Company Project), which had been previously purchased and held by the Company since December 2013.

In September 2014, the Company issued $200 million aggregate principal amount of Series 2014A 4.55% Senior Notes due October 1, 2044. The proceeds were used to repay a portion of the Company's outstanding short-term indebtedness, for general corporate purposes, including the Company's continuous construction program, and for repayment at maturity $75 million aggregate principal amount of the Company's Series K 4.90% Senior Notes due October 1, 2014.

Subsequent to December 31, 2014, the Company issued 200,000 shares of common stock to Southern Company and realized proceeds of $20 million. The proceeds were used to repay a portion of the Company's short-term debt and for other general corporate purposes, including the Company's continuous construction program.

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

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Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade.

There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel transportation and storage, and energy price risk management. The maximum potential collateral requirements under these contracts at December 31, 2014 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements (in millions)
At BBB- and/or Baa3	$74
Below BBB- and/or Baa3	447

Included in these amounts are certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact the Company's ability to access capital markets, particularly the short-term debt market and the variable rate pollution control revenue bond market.

Market Price Risk

Due to cost-based rate regulation and other various cost recovery mechanisms, the Company continues to have limited exposure to market volatility in interest rates, commodity fuel prices, and prices of electricity. To manage the volatility attributable to these exposures, the Company nets the exposures, where possible, to take advantage of natural offsets and may enter into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis.

To mitigate future exposure to changes in interest rates, the Company may enter into derivatives which are designated as hedges. The weighted average interest rate on $69.3 million of outstanding variable rate long-term debt that has not been hedged at January 1, 2015 was .02%. If the Company sustained a 100 basis point change in interest rates for all variable rate long-term debt, the change would affect annualized interest expense by approximately $0.7 million at January 1, 2015. See Note 1 to the financial statements under "Financial Instruments" and Note 10 to the financial statements for additional information.

To mitigate residual risks relative to movements in fuel and electricity prices, the Company enters into financial hedge contracts for natural gas purchases and physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market. The Company continues to manage a fuel-hedging program implemented per the guidelines of the Florida PSC and the actual cost of fuel is recovered through the retail fuel clause. The Company had no material change in market risk exposure for the year ended December 31, 2014 when compared to the year ended December 31, 2013.

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:

	2014 Changes Fair Value	2013 Changes

	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	$(10)	$(23)
Contracts realized or settled	(3)	13
Current period changes[a]	(59)	—
Contracts outstanding at the end of the period, assets (liabilities), net	$(72)	$(10)

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

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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The net hedge volumes of energy-related derivative contracts for the years ended December 31 were as follows:

	2014	2013
	mmBtu Volume (in millions)	
Commodity – Natural gas swaps	85	87
Commodity – Natural gas options	—	2
Total hedge volume	85	89

The weighted average swap contract cost above market prices was approximately $0.80 per mmBtu as of December 31, 2014 and $0.12 per mmBtu as of December 31, 2013. The change in option fair value is primarily attributable to the volatility of the market and the underlying change in the natural gas price. Natural gas settlements are recovered through the Company's fuel cost recovery clause.

At December 31, 2014 and 2013, substantially all of the Company's energy-related derivative contracts were designated as regulatory hedges and were related to the Company's fuel-hedging program. Therefore, gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the fuel cost recovery clause. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred and were not material for any year presented and the actual cost of fuel is recovered through the retail fuel clause.

The Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. See Note 9 to the financial statements for further discussion of fair value measurements. The maturities of the energy-related derivative contracts, which are all Level 2 of the fair value hierarchy, at December 31, 2014 were as follows:

	Fair Value Measurements December 31, 2014			
	Total	Maturity		
	Fair Value	Year 1	Years 2&3	Years 4&5
	(in millions)			
Level 1	$—	$—	$—	$—
Level 2	(72)	(37)	(33)	(2)
Level 3	—	—	—	—
Fair value of contracts outstanding at end of period	$(72)	$(37)	$(33)	$(2)

The Company is exposed to market price risk in the event of nonperformance by counterparties to the energy-related derivative contracts. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P, or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Note 1 to the financial statements under "Financial Instruments" and Note 10 to the financial statements.

Capital Requirements and Contractual Obligations

The construction program of the Company is currently estimated to be $263 million for 2015, $186 million for 2016, and $168 million for 2017. Capital expenditures to comply with environmental statutes and regulations included in these amounts are estimated to be $127 million, $39 million, and $38 million for 2015, 2016, and 2017, respectively. These amounts include capital expenditures related to contractual purchase commitments for capital expenditures covered under long-term service agreements. These estimated expenditures do not include any potential compliance costs that may arise from the EPA's proposed rules that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Global Climate Issues" for additional information.

See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" for additional information.
The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; storm impacts;

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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changes in environmental statutes and regulations; the outcome of any legal challenges to the environmental rules; changes in generating plants, including unit retirements and replacements and adding or changing fuel sources at existing units, to meet regulatory requirements; changes in the expected environmental compliance program; changes in FERC rules and regulations; Florida PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

In addition, as discussed in Note 2 to the financial statements, the Company provides postretirement benefits to substantially all employees and funds trusts to the extent required by the FERC and the Florida PSC.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preference stock dividends, leases, and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 1, 2, 5, 6, 7, and 10 to the financial statements for additional information.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Gulf Power Company 2014 Annual Report

Contractual Obligations

	2015	2016-2017	2018-2019	After 2019	Total
	(in thousands)				
Long-term debt[a] –					
Principal	$—	$195,000	$—	$1,183,955	$1,378,955
Interest	57,546	109,262	93,402	853,213	1,113,423
Financial derivative obligations[b]	36,934	32,938	2,563	—	72,435
Preference stock dividends[c]	9,003	18,006	18,006	—	45,015
Operating leases[d]	15,239	16,624	—	—	31,863
Unrecognized tax benefits[e]	46	—	—	—	46
Purchase commitments –					
Capital[f]	262,814	326,536	—	—	589,350
Fuel[g]	276,437	349,155	255,854	145,535	1,026,981
Purchased power[h]	92,395	183,929	182,929	315,331	774,584
Other[i]	16,498	20,616	15,820	43,145	96,079
Pension and other postretirement benefit plans[j]	4,716	10,061	—	—	14,777
Total	$771,628	$1,262,127	$568,574	$2,541,179	$5,143,508

(a) All amounts are reflected based on final maturity dates. The Company plans to continue to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of January 1, 2015, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk.
(b) For additional information, see Notes 1 and 10 to the financial statements.
(c) Preference stock does not mature; therefore, amounts are provided for the next five years only.
(d) Excludes a PPA accounted for as a lease and is included in purchased power.
(e) See Note 5 to the financial statements under "Unrecognized Tax Benefits" for additional information.
(f) The Company provides estimated capital expenditures for a three-year period, including capital expenditures and compliance costs associated with environmental regulations. These amounts exclude capital expenditures covered under long-term service agreements, which are reflected in Other. At December 31, 2014, significant purchase commitments were outstanding in connection with the construction program. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" for additional information.
(g) Includes commitments to purchase coal and natural gas, as well as the related transportation and storage. In most cases, these contracts contain provisions for price escalation, minimum purchase levels, and other financial commitments. Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected for natural gas purchase commitments have been estimated based on the New York Mercantile Exchange future prices at December 31, 2014.
(h) The capacity and transmission related costs associated with PPAs are recovered through the purchased power capacity clause. See Notes 3 and 7 to the financial statements for additional information.
(i) Includes long-term service agreements and contracts for the procurement of limestone. Long-term service agreements include price escalation based on inflation indices. Limestone costs are recovered through the environmental cost recovery clause. See Note 3 to the financial statements for additional information.
(j) The Company forecasts contributions to the pension and other postretirement benefit plans over a three-year period. The Company anticipates no mandatory contributions to the qualified pension plan during the next three years. Amounts presented represent estimated benefit payments for the nonqualified pension plans, estimated non-trust benefit payments for the other postretirement benefit plans, and estimated contributions to the other postretirement

benefit plan trusts, all of which will be made from the Company's corporate assets. See Note 2 to the financial statements for additional information related to the pension and other postretirement benefit plans, including estimated benefit payments. Certain benefit payments will be made through the related benefit plans. Other benefit payments will be made from the Company's corporate assets.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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Cautionary Statement Regarding Forward-Looking Statements
The Company's 2014 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail rates, economic recovery, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related compliance plans and estimated expenditures, access to sources of capital, projections for the qualified pension plan and postretirement benefit plan contributions, financing activities, start and completion of construction projects, filings with state and federal regulatory authorities, impact of the TIPA, estimated sales and purchases under power sale and purchase agreements, and estimated construction and other plans and expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, environmental laws including regulation of water, CCR, and emissions of sulfur, nitrogen, CO_2, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, and also changes in tax and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including pending EPA civil action against the Company and IRS and state tax audits;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the last recession, population and business growth (and declines), the effects of energy conservation and efficiency measures, including from the development and deployment of alternative energy sources such as self-generation and distributed generation technologies, and any potential economic impacts resulting from federal fiscal decisions;
- available sources and costs of fuels;
- effects of inflation;
- the ability to control costs and avoid cost overruns during the development and construction of facilities, to construct facilities in accordance with the requirements of permits and licenses, and to satisfy any operational and environmental performance standards;
- investment performance of the Company's employee and retiree benefit plans;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms;
- the ability to successfully operate generating, transmission, and distribution facilities and the successful performance of necessary corporate functions;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Company's business resulting from cyber intrusion or terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and financial market conditions and the results of financing efforts;
-

changes in the Company's credit ratings, including impacts on interest rates, access to capital markets, and collateral requirements;

- the impacts of any sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on currency exchange rates, counterparty performance, and the economy in general;
- the ability of the Company to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes and other storms, droughts, pandemic health events such as influenzas, or other similar occurrences;

- the direct or indirect effects on the Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

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

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STATEMENTS OF INCOME
For the Years Ended December 31, 2014, 2013, and 2012
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	2014	2013	2012
	(in thousands)		
Operating Revenues:			
Retail revenues	$1,266,540	$1,170,000	$1,144,471
Wholesale revenues, non-affiliates	129,151	109,386	106,881
Wholesale revenues, affiliates	130,107	99,577	123,636
Other revenues	64,684	61,338	64,774
Total operating revenues	1,590,482	1,440,301	1,439,762
Operating Expenses:			
Fuel	604,641	532,791	544,936
Purchased power, non-affiliates	81,993	52,443	51,421
Purchased power, affiliates	25,246	32,835	22,665
Other operations and maintenance	341,214	309,865	314,195
Depreciation and amortization	145,026	149,009	141,038
Taxes other than income taxes	111,147	98,355	97,313
Total operating expenses	1,309,267	1,175,298	1,171,568
Operating Income	281,215	265,003	268,194
Other Income and (Expense):			
Allowance for equity funds used during construction	12,021	6,448	5,221
Interest income	90	369	1,408
Interest expense, net of amounts capitalized	(53,234)	(56,025)	(60,250)
Other income (expense), net	(2,851)	(3,994)	(3,227)
Total other income and (expense)	(43,974)	(53,202)	(56,848)
Earnings Before Income Taxes	237,241	211,801	211,346
Income taxes	88,062	79,668	79,211
Net Income	149,179	132,133	132,135
Dividends on Preference Stock	9,003	7,704	6,203
Net Income After Dividends on Preference Stock	$140,176	$124,429	$125,932

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

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STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2014, 2013, and 2012
Gulf Power Company 2014 Annual Report

	2014	2013	2012
	(in thousands)		
Net Income	$149,179	$132,133	$132,135
Other comprehensive income (loss):			
Qualifying hedges:			
Reclassification adjustment for amounts included in net income, net of tax of $234, $297, and $360, respectively	372	472	573
Total other comprehensive income (loss)	372	472	573
Comprehensive Income	$149,551	$132,605	$132,708

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

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STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2014, 2013, and 2012
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	2014	2013	2012
	(in thousands)		
Operating Activities:			
Net income	$149,179	$132,133	$132,135
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization, total	152,670	155,798	147,723
Deferred income taxes	65,330	77,069	174,305
Allowance for equity funds used during construction	(12,021)	(6,448)	(5,221)
Pension, postretirement, and other employee benefits	(23,305)	11,422	(8,109)
Stock based compensation expense	1,928	1,749	1,647
Other, net	(1,233)	5,865	4,518
Changes in certain current assets and liabilities —			
-Receivables	(17,178)	(49,051)	8,713
-Fossil fuel stock	33,603	19,468	(6,144)
-Materials and supplies	(721)	(1,570)	(3,035)
-Prepaid income taxes	(19,179)	15,526	355
-Other current assets	(883)	682	417
-Accounts payable	8,279	(6,964)	(5,195)
-Accrued taxes	(1,924)	(4,759)	(4,705)
-Accrued compensation	11,237	(3,309)	481
-Over recovered regulatory clause revenues	—	(17,092)	(10,858)
-Other current liabilities	(2,704)	(782)	(7,837)
Net cash provided from operating activities	343,078	329,737	419,190
Investing Activities:			
Property additions	(348,305)	(292,914)	(313,257)
Cost of removal net of salvage	(12,932)	(13,827)	(28,993)
Construction payables	11,574	6,796	1,161
Payments pursuant to long-term service agreements	(8,012)	(7,109)	(8,119)
Other investing activities	(19)	496	656
Net cash used for investing activities	(357,694)	(306,558)	(348,552)
Financing Activities:			
Increase (decrease) in notes payable, net	(25,900)	12,108	16,075
Proceeds —			
Common stock issued to parent	50,000	40,000	40,000
Capital contributions from parent company	4,037	2,987	2,106
Preference stock	—	50,000	—
Pollution control revenue bonds	42,075	63,000	13,000
Senior notes	200,000	90,000	100,000
Redemptions —			
Pollution control revenue bonds	(29,075)	(76,000)	(13,000)
Senior notes	(75,000)	(90,000)	(91,363)
Payment of preference stock dividends	(9,003)	(7,004)	(6,203)
Payment of common stock dividends	(123,200)	(115,400)	(115,800)
Other financing activities	(2,457)	(3,284)	(614)

Net cash provided from (used for) financing activities	31,477	(33,593)	(55,799)
Net Change in Cash and Cash Equivalents	16,861	(10,414)	14,839
Cash and Cash Equivalents at Beginning of Year	21,753	32,167	17,328
Cash and Cash Equivalents at End of Year	$38,614	$21,753	$32,167
Supplemental Cash Flow Information:			
Cash paid (received) during the period for —			
Interest (net of $5,373, $3,421 and $2,500 capitalized, respectively)	$48,030	$53,401	$58,255
Income taxes (net of refunds)	44,125	(10,727)	(96,639)
Noncash transactions — accrued property additions at year-end	41,526	31,546	27,369

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

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BALANCE SHEETS
At December 31, 2014 and 2013
Gulf Power Company 2014 Annual Report

Assets	2014	2013
	(in thousands)	
Current Assets:		
Cash and cash equivalents	$38,614	$21,753
Receivables —		
Customer accounts receivable	73,000	64,884
Unbilled revenues	58,268	57,282
Under recovered regulatory clause revenues	57,153	48,282
Other accounts and notes receivable	8,145	8,620
Affiliated companies	9,867	8,259
Accumulated provision for uncollectible accounts	(2,087)	(1,131)
Fossil fuel stock, at average cost	101,447	135,050
Materials and supplies, at average cost	55,656	54,935
Other regulatory assets, current	74,242	18,536
Prepaid expenses	39,673	33,186
Other current assets	1,711	6,120
Total current assets	515,689	455,776
Property, Plant, and Equipment:		
In service	4,494,953	4,363,664
Less accumulated provision for depreciation	1,295,714	1,211,336
Plant in service, net of depreciation	3,199,239	3,152,328
Construction work in progress	465,033	280,626
Total property, plant, and equipment	3,664,272	3,432,954
Other Property and Investments	15,148	15,314
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	55,931	50,597
Prepaid pension costs	—	11,533
Other regulatory assets, deferred	416,028	340,415
Other deferred charges and assets	41,191	30,982
Total deferred charges and other assets	513,150	433,527
Total Assets	$4,708,259	$4,337,571

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

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BALANCE SHEETS
At December 31, 2014 and 2013
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Liabilities and Stockholder's Equity	2014	2013
	(in thousands)	
Current Liabilities:		
Securities due within one year	$—	$75,000
Notes payable	109,977	135,878
Accounts payable —		
Affiliated	87,397	76,897
Other	55,848	47,038
Customer deposits	35,094	34,433
Accrued taxes —		
Accrued income taxes	46	45
Other accrued taxes	9,201	7,486
Accrued interest	10,686	10,272
Accrued compensation	22,894	11,657
Deferred capacity expense, current	21,988	—
Other regulatory liabilities, current	566	13,408
Liabilities from risk management activities	36,934	6,470
Other current liabilities	22,386	22,972
Total current liabilities	413,017	441,556
Long-Term Debt (See accompanying statements)	1,369,594	1,158,163
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	799,723	734,355
Accumulated deferred investment tax credits	2,783	4,055
Employee benefit obligations	120,752	76,338
Deferred capacity expense	163,077	180,149
Other cost of removal obligations	234,587	228,148
Other regulatory liabilities, deferred	48,556	56,051
Other deferred credits and liabilities	100,076	77,126
Total deferred credits and other liabilities	1,469,554	1,356,222
Total Liabilities	3,252,165	2,955,941
Preference Stock (See accompanying statements)	146,504	146,504
Common Stockholder's Equity (See accompanying statements)	1,309,590	1,235,126
Total Liabilities and Stockholder's Equity	$4,708,259	$4,337,571
Commitments and Contingent Matters (See notes)		

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

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STATEMENTS OF CAPITALIZATION
At December 31, 2014 and 2013
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	2014	2013	2014	2013
	(in thousands)		(percent of total)	
Long-Term Debt:				
Long-term notes payable —				
4.90% due 2014	—	75,000		
5.30% due 2016	110,000	110,000		
5.90% due 2017	85,000	85,000		
3.10% to 5.75% due 2020-2051	875,000	675,000		
Total long-term notes payable	1,070,000	945,000		
Other long-term debt —				
Pollution control revenue bonds —				
0.55% to 6.00% due 2022-2049	239,625	226,625		
Variable rates (0.02% to 0.04% at 1/1/15) due 2022-2039	69,330	69,330		
Total other long-term debt	308,955	295,955		
Unamortized debt discount	(9,361)	(7,792)		
Total long-term debt (annual interest requirement — $57.5 million)	1,369,594	1,233,163		
Less amount due within one year	—	75,000		
Long-term debt excluding amount due within one year	1,369,594	1,158,163	48.5%	45.6%
Preferred and Preference Stock:				
Authorized — 20,000,000 shares — preferred stock				
— 10,000,000 shares — preference stock				
Outstanding — $100 par or stated value				
— 6% preference stock — 550,000 shares (non-cumulative)	53,886	53,886		
— 6.45% preference stock — 450,000 shares (non-cumulative)	44,112	44,112		
— 5.60% preference stock — 500,000 shares (non-cumulative)	48,506	48,506		
Total preference stock (annual dividend requirement — $9.0 million)	146,504	146,504	5.2	5.8
Common Stockholder's Equity:				
Common stock, without par value —				
Authorized — 20,000,000 shares				
Outstanding — 2014: 5,442,717 shares				
— 2013: 4,942,717 shares	483,060	433,060		
Paid-in capital	559,797	552,681		
Retained earnings	267,470	250,494		
Accumulated other comprehensive loss	(737)	(1,109)		
Total common stockholder's equity	1,309,590	1,235,126	46.3	48.6
Total Capitalization	$2,825,688	$2,539,793	100.0%	100.0%

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

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STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
For the Years Ended December 31, 2014, 2013, and 2012
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	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
	(in thousands)					
Balance at December 31, 2011	4,143	$353,060	$542,709	$231,333	$(2,154)	$1,124,948
Net income after dividends on preference stock	—	—	—	125,932	—	125,932
Issuance of common stock	400	40,000	—	—	—	40,000
Capital contributions from parent company	—	—	5,089	—	—	5,089
Other comprehensive income (loss)	—	—	—	—	573	573
Cash dividends on common stock	—	—	—	(115,800)	—	(115,800)
Balance at December 31, 2012	4,543	393,060	547,798	241,465	(1,581)	1,180,742
Net income after dividends on preference stock	—	—	—	124,429	—	124,429
Issuance of common stock	400	40,000	—	—	—	40,000
Capital contributions from parent company	—	—	4,883	—	—	4,883
Other comprehensive income (loss)	—	—	—	—	472	472
Cash dividends on common stock	—	—	—	(115,400)	—	(115,400)
Balance at December 31, 2013	4,943	433,060	552,681	250,494	(1,109)	1,235,126
Net income after dividends on preference stock	—	—	—	140,176	—	140,176
Issuance of common stock	500	50,000	—	—	—	50,000
Capital contributions from parent company	—	—	7,116	—	—	7,116
Other comprehensive income (loss)	—	—	—	—	372	372
Cash dividends on common stock	—	—	—	(123,200)	—	(123,200)
Balance at December 31, 2014	5,443	$483,060	$559,797	$267,470	$(737)	$1,309,590

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

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NOTES TO FINANCIAL STATEMENTS
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1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES
General
Gulf Power Company (the Company) is a wholly-owned subsidiary of The Southern Company (Southern Company), which is the parent company of four traditional operating companies, as well as Southern Power, SCS, SouthernLINC Wireless, Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear, and other direct and indirect subsidiaries. The traditional operating companies – the Company, Alabama Power, Georgia Power, and Mississippi Power – are vertically integrated utilities providing electric service in four Southeastern states. The Company operates as a vertically integrated utility providing electricity to retail customers in northwest Florida and to wholesale customers in the Southeast. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary, primarily for Southern Company's investments in leveraged leases. Southern Nuclear operates and provides services to the Southern Company system's nuclear power plants.
The equity method is used for entities in which the Company has significant influence but does not control.
The Company is subject to regulation by the FERC and the Florida PSC. The Company follows GAAP in the U.S. and complies with the accounting policies and practices prescribed by its regulatory commissions. The preparation of financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates. Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation.
Recently Issued Accounting Standards
On May 28, 2014, the Financial Accounting Standards Board issued ASC 606, Revenue from Contracts with Customers. ASC 606 revises the accounting for revenue recognition and is effective for fiscal years beginning after December 15, 2016. The Company continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.
Affiliate Transactions
The Company has an agreement with SCS under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, operations, purchasing, accounting, finance and treasury, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, and other services with respect to business and operations, construction management, and power pool transactions. Costs for these services amounted to $79.6 million, $78.4 million, and $95.9 million during 2014, 2013, and 2012, respectively. Cost allocation methodologies used by SCS prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, were approved by the SEC. Subsequently, additional cost allocation methodologies have been reported to the FERC and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies.
The Company has operating agreements with Georgia Power and Mississippi Power under which the Company owns a portion of Plant Scherer and Plant Daniel, respectively. Georgia Power operates Plant Scherer and Mississippi Power operates Plant Daniel. The Company reimbursed Georgia Power $8.7 million, $10.2 million, and $6.9 million and Mississippi Power $30.5 million, $16.5 million, and $21.1 million in 2014, 2013, and 2012, respectively, for its proportionate share of related expenses. See Note 4 and Note 7 under "Operating Leases" for additional information.
The Company entered into a PPA with Southern Power for approximately 292 MWs annually from June 2009 through May 2014. Purchased power expenses associated with the PPA were $1.8 million, $14.2 million, and $14.7 million in 2014, 2013, and 2012, respectively, and fuel costs associated with the PPA were $1.7 million, $0.8 million, and $2.6 million in 2014, 2013, and 2012, respectively. These costs were approved for recovery by the Florida PSC through the Company's fuel and purchased power capacity cost recovery clauses. See Note 7 under "Fuel and Purchased Power

Agreements" for additional information.

The Company had an agreement with Georgia Power under the transmission facility cost allocation tariff for delivery of power from the Company's resources in the state of Georgia. The Company reimbursed Georgia Power $1.0 million in 2014 and $2.4 million in each of the years 2013 and 2012 for its share of related expenses.

The Company has an agreement with Alabama Power under which Alabama Power has made transmission system upgrades to ensure firm delivery of energy under a non-affiliate PPA, which was entered into in 2009 for the capacity and energy from a combined cycle plant located in Autauga County, Alabama. Revenue requirement obligations to Alabama Power for these upgrades are estimated to be $132.0 million for the entire project. These costs began in July 2012 and will continue through 2023.

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The Company reimbursed Alabama Power $11.9 million, $7.9 million, and $3.0 million in 2014, 2013, and 2012, respectively, for the revenue requirements. These costs have been approved for recovery by the Florida PSC through the Company's purchased power capacity cost recovery clause and by the FERC in the transmission facilities cost allocation tariff.
The Company provides incidental services to and receives such services from other Southern Company subsidiaries which are generally minor in duration and amount. Except as described herein, the Company neither provided nor received any material services to or from affiliates in 2014, 2013, or 2012.
The traditional operating companies, including the Company, and Southern Power may jointly enter into various types of wholesale energy, natural gas, and certain other contracts, either directly or through SCS, as agent. Each participating company may be jointly and severally liable for the obligations incurred under these agreements. See Note 7 under "Fuel and Purchased Power Agreements" for additional information.

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Regulatory Assets and Liabilities

The Company is subject to the provisions of the Financial Accounting Standards Board in accounting for the effects of rate regulation. Regulatory assets represent probable future revenues associated with certain costs that are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are expected to be credited to customers through the ratemaking process.

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

	2014	2013	Note
	(in thousands)		
Deferred income tax charges	$53,234	$47,573	(a)
Deferred income tax charges — Medicare subsidy	3,024	3,351	(b)
Asset retirement obligations	(5,087)	(6,089)	(a,j)
Other cost of removal obligations	(242,997)	(228,148)	(a)
Regulatory asset, offset to other cost of removal	8,410	—	(m)
Deferred income tax credits	(3,872)	(5,238)	(a)
Loss on reacquired debt	15,991	16,565	(c)
Vacation pay	10,006	9,521	(d,j)
Under recovered regulatory clause revenues	52,619	45,191	(e)
Property damage reserve	(35,111)	(35,380)	(f)
Fuel-hedging (realized and unrealized) losses	73,474	17,043	(g,j)
Fuel-hedging (realized and unrealized) gains	(112)	(6,962)	(g,j)
PPA charges	185,065	180,149	(j,k)
Other regulatory assets	9,753	12,772	(l)
Environmental remediation	48,271	50,384	(h,j)
Other regulatory liabilities	(649)	(8,804)	(f,j)
Retiree benefit plans, net	147,625	68,296	(i,j)
Total regulatory assets (liabilities), net	$319,644	$160,224	

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

(a) Asset retirement and removal assets and liabilities are recorded, deferred income tax assets are recovered, and deferred income tax liabilities are amortized over the related property lives, which may range up to 65 years. Asset retirement and removal assets and liabilities will be settled and trued up following completion of the related activities.

(b) Recovered and amortized over periods not exceeding 14 years.

(c) Recovered over either the remaining life of the original issue or, if refinanced, over the life of the new issue, which may range up to 40 years.

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

(e) Recorded and recovered or amortized as approved by the Florida PSC, generally within one year.

(f) Recorded and recovered or amortized as approved by the Florida PSC.

(g) Fuel-hedging assets and liabilities are recognized over the life of the underlying hedged purchase contracts, which generally do not exceed five years. Upon final settlement, actual costs incurred are recovered through the fuel cost recovery clause.

(h) Recovered through the environmental cost recovery clause when the remediation is performed.

(i) Recovered and amortized over the average remaining service period which may range up to 14 years. See Note 2 for additional information.

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

(k) Recovered over the life of the PPA for periods up to nine years.

(l) Comprised primarily of net book value of retired meters, deferred rate case expenses, and generation site evaluation costs. These costs are recorded and recovered or amortized as approved by the Florida PSC, generally over periods not exceeding eight years, or deferred pursuant to Florida statute while the Company continues to evaluate certain potential new generating projects.

(m) Recorded as authorized by the Florida PSC in a settlement agreement approved in December 2013. See Note 3 for additional information.

In the event that a portion of the Company's operations is no longer subject to applicable accounting rules for rate regulation, the Company would be required to write off to income or reclassify to accumulated OCI related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the Company would be required to determine if any

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impairment to other assets, including plant, exists and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are to be reflected in rates. See Note 3 under "Retail Regulatory Matters" for additional information.

Revenues

Wholesale capacity revenues are generally recognized on a levelized basis over the appropriate contract period. Energy and other revenues are recognized as services are provided. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, the energy component of purchased power costs, and certain other costs. The Company continuously monitors the over or under recovered fuel cost balance in light of the inherent variability in fuel costs. The Company is required to notify the Florida PSC if the projected fuel cost over or under recovery is expected to exceed 10% of the projected fuel revenue applicable for the period and indicate if an adjustment to the fuel cost recovery factor is being requested. The Company has similar retail cost recovery clauses for energy conservation costs, purchased power capacity costs, and environmental compliance costs. Revenues are adjusted for differences between these actual costs and amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors. Annually, the Company petitions for recovery of projected costs including any true-up amounts from prior periods, and approved rates are implemented each January. See Note 3 under "Retail Regulatory Matters" for additional information.

The Company has a diversified base of customers. No single customer or industry comprises 10% or more of revenues. For all periods presented, uncollectible accounts averaged less than 1% of revenues.

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense generally includes fuel transportation costs and the cost of purchased emissions allowances as they are used. Fuel expense and emissions allowance costs are recovered by the Company through the fuel cost recovery and environmental cost recovery rates, respectively, approved annually by the Florida PSC.

Income and Other Taxes

The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. Federal ITCs utilized are deferred and amortized to income over the average life of the related property and state ITCs are recognized in the period in which the credit is claimed on the state income tax return. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income.

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

Property, Plant, and Equipment

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

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

	2014	2013
	(in thousands)	
Generation	$2,637,817	$2,607,166
Transmission	515,754	473,378
Distribution	1,156,872	1,117,024
General	182,734	164,065

Plant acquisition adjustment	1,776	2,031
Total plant in service	$4,494,953	$4,363,664

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.

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Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.6% in 2014, 2013, and 2012. Depreciation studies are conducted periodically to update the composite rates. These studies are approved by the Florida PSC and the FERC. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation are removed from the balance sheet accounts, and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired. As authorized by the Florida PSC in the settlement agreement approved in December 2013 (Settlement Agreement), the Company is allowed to reduce depreciation expense and record a regulatory asset in an aggregate amount up to $62.5 million between January 2014 and June 2017. See Note 3 herein under "Retail Regulatory Matters – Retail Base Rate Case" for additional information.

Asset Retirement Obligations and Other Costs of Removal

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

The liability for AROs primarily relates to the Company's combustion turbines at its Pea Ridge facility, various landfill sites, a barge unloading dock, asbestos removal, ash ponds, and disposal of polychlorinated biphenyls in certain transformers. The Company also has identified retirement obligations related to certain transmission and distribution facilities, certain wireless communication towers, and certain structures authorized by the U.S. Army Corps of Engineers. However, liabilities for the removal of these assets have not been recorded because the settlement timing for the retirement obligations related to these assets is indeterminable and, therefore, the fair value of the retirement obligations cannot be reasonably estimated. A liability for these AROs will be recognized when sufficient information becomes available to support a reasonable estimation of the ARO. The Company will continue to recognize in the statements of income allowed removal costs in accordance with its regulatory treatment. Any differences between costs recognized in accordance with accounting standards related to asset retirement and environmental obligations and those reflected in rates are recognized as either a regulatory asset or liability, as ordered by the Florida PSC, and are reflected in the balance sheets.

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

	2014	2013
	(in thousands)	
Balance at beginning of year	$16,184	$16,055
Liabilities incurred	—	518
Liabilities settled	(32)	(1,913)
Accretion	718	751
Cash flow revisions	(159)	773
Balance at end of year	$16,711	$16,184

The 2014 cash flow revisions are associated with asbestos and ash ponds at the Company's steam generation facilities. The 2013 cash flow revisions are associated with asbestos and an unloading dock at its generation facilities.

On December 19, 2014, the EPA issued the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule), but has not yet published it in the Federal Register. The CCR Rule will regulate the disposal of CCR, including coal ash and gypsum, as non-hazardous solid waste in landfills and surface impoundments at active generating power plants. The ultimate impact of the CCR Rule cannot be determined at this time and will depend on the Company's ongoing review of the CCR Rule, the results of initial and ongoing minimum criteria assessments, and the outcome of legal challenges. The cost and timing of potential ash pond closure and ongoing monitoring activities that may be required in connection with the CCR Rule is also uncertain; however, the Company has developed a preliminary nominal dollar estimate of costs associated with closure and groundwater monitoring of ash ponds in place of approximately $62 million and ongoing post-closure care of approximately $11 million. The Company has previously recorded AROs associated with ash ponds of $6 million, or $11 million on a nominal dollar basis, based on existing state requirements. During 2015, the Company will record AROs for any incremental estimated closure costs resulting from acceleration in the timing of any currently planned closures and for differences between existing state

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requirements and the requirements of the CCR Rule. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates.

Allowance for Funds Used During Construction

In accordance with regulatory treatment, the Company records AFUDC, which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently from such allowance, AFUDC increases the revenue requirement 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. The average annual AFUDC rate was 5.73% for 2014, 6.26% for 2013, and 6.72% for 2012. AFUDC, net of income taxes, as a percentage of net income after dividends on preference stock was 10.93%, 6.87%, and 5.36% for 2014, 2013, and 2012, respectively.

Impairment of Long-Lived Assets and Intangibles

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

Property Damage Reserve

The Company accrues for the cost of repairing damages from major storms and other uninsured property damages, including uninsured damages to transmission and distribution facilities, generation facilities, and other property. The costs of such damage are charged to the reserve. The Florida PSC approved annual accrual to the property damage reserve is $3.5 million, with a target level for the reserve between $48.0 million and $55.0 million. The Florida PSC also authorized the Company to make additional accruals above the $3.5 million at the Company's discretion. The Company accrued total expenses of $3.5 million in each of 2014, 2013, and 2012. As of December 31, 2014 and 2013, the balance in the Company's property damage reserve totaled approximately $35.7 million and $35.4 million, respectively, which is included in deferred liabilities in the balance sheets.

When the property damage reserve is inadequate to cover the cost of major storms, the Florida PSC can authorize a storm cost recovery surcharge to be applied to customer bills. In December 2013, the Florida PSC approved the Settlement Agreement that, among other things, 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 the Company 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. See Note 3 herein under "Retail Regulatory Matters – Retail Base Rate Case" for additional details of the Settlement Agreement.

Injuries and Damages Reserve

The Company is subject to claims and lawsuits arising in the ordinary course of business. As permitted by the Florida PSC, the Company accrues for the uninsured costs of injuries and damages by charges to income amounting to $1.6 million annually. The Florida PSC has also given the Company the flexibility to increase its annual accrual above $1.6 million to the extent the balance in the reserve does not exceed $2.0 million and to defer expense recognition of liabilities greater than the balance in the reserve. The cost of settling claims is charged to the reserve. The injuries and damages reserve was $4.0 million and $3.6 million at December 31, 2014 and 2013, respectively. For 2014, $1.6

million and $2.4 million are included in current liabilities and deferred credits and other liabilities in the balance sheets, respectively. For 2013, $1.6 million and $2.0 million are included in current liabilities and deferred credits and other liabilities in the balance sheets, respectively. There were no liabilities in excess of the reserve balance at December 31, 2014 or 2013.

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.

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Materials and Supplies
Generally, materials and supplies include the average cost of transmission, distribution, and generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when installed.
Fuel Inventory
Fuel inventory includes the average cost of oil, natural gas, coal, transportation, and emissions allowances. Fuel is charged to inventory when purchased and then expensed, at weighted average cost, as used. Fuel expense and emissions allowance costs are recovered by the Company through the fuel cost recovery and environmental cost recovery rates, respectively, approved annually by the Florida PSC. Emissions allowances granted by the EPA are included in inventory at zero cost.
Financial Instruments
The Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, and electricity purchases and sales. All derivative financial instruments are recognized as either assets or liabilities (included in "Other" or shown separately as "Risk Management Activities") and are measured at fair value. See Note 9 for additional information regarding fair value. Substantially all of the Company's bulk energy purchases and sales contracts that meet the definition of a derivative are excluded from fair value accounting requirements because they qualify for the "normal" scope exception, and are accounted for under the accrual method. Derivative contracts that qualify as cash flow hedges of anticipated transactions or are recoverable through the Florida PSC approved fuel-hedging program result in the deferral of related gains and losses in OCI or regulatory assets and liabilities, respectively, until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts that qualify as fair value hedges are marked to market through current period income and are recorded on a net basis in the statements of income. See Note 10 for additional information regarding derivatives.
The Company does not offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. Additionally, the Company had no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2014.
The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company has established controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk.
Comprehensive Income
The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income, changes in the fair value of qualifying cash flow hedges, and reclassifications for amounts included in net income.
2. RETIREMENT BENEFITS
The Company has a defined benefit, trusteed, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). In December 2014, the Company voluntarily contributed $30 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2015. The Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The Company funds its other postretirement trusts to the extent required by the FERC. For the year ending December 31, 2015, no other postretirement trust contributions are expected.
Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine both the benefit obligations as of the measurement date and the net periodic costs for the pension and other postretirement benefit plans for the following year are presented below. Net periodic benefit costs were calculated in 2011 for the 2012 plan year using discount rates for the pension plans and the other postretirement benefit plans of 4.98% and 4.88%, respectively, and an annual salary increase of 3.84%.

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	2014		2013		2012	
Discount rate:						
Pension plans	4.18	%	5.02	%	4.27	%
Other postretirement benefit plans	4.04		4.86		4.06	
Annual salary increase	3.59		3.59		3.59	
Long-term return on plan assets:						
Pension plans	8.20		8.20		8.20	
Other postretirement benefit plans	8.08		8.04		8.02	

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

For purposes of its December 31, 2014 measurement date, the Company adopted new mortality tables for its pension plans and retiree life and medical plans, which reflect increased life expectancies in the U.S. The adoption of new mortality tables increased the projected benefit obligations for the Company's pension plans and other postretirement benefit plans by approximately $29.6 million and $2.6 million, respectively.

An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) was a weighted average medical care cost trend rate. The weighted average medical care cost trend rates used in measuring the APBO as of December 31, 2014 were as follows:

	Initial Cost Trend Rate		Ultimate Cost Trend Rate		Year That Ultimate Rate is Reached
Pre-65	9.00	%	4.50	%	2024
Post-65 medical	6.00		4.50		2024
Post-65 prescription	6.75		4.50		2024

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, 2014 as follows:

	1 Percent Increase	1 Percent Decrease	
	(in thousands)		
Benefit obligation	$3,934	$(3,334	)
Service and interest costs	157	(133	)

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Pension Plans
The total accumulated benefit obligation for the pension plans was $438 million at December 31, 2014 and $353 million at December 31, 2013. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2014 and 2013 were as follows:

	2014	2013
	(in thousands)	
Change in benefit obligation		
Benefit obligation at beginning of year	$395,328	$413,501
Service cost	10,181	11,128
Interest cost	19,433	17,321
Benefits paid	(15,635)	(14,831)
Actuarial (gain) loss	81,254	(31,791)
Balance at end of year	490,561	395,328
Change in plan assets		
Fair value of plan assets at beginning of year	385,639	350,260
Actual return on plan assets	33,512	49,076
Employer contributions	31,251	1,134
Benefits paid	(15,635)	(14,831)
Fair value of plan assets at end of year	434,767	385,639
Accrued liability	$(55,794)	$(9,689)

At December 31, 2014, the projected benefit obligations for the qualified and non-qualified pension plans were $464 million and $26 million, respectively. All pension plan assets are related to the qualified pension plan.
Amounts recognized in the balance sheets at December 31, 2014 and 2013 related to the Company's pension plans consist of the following:

	2014	2013
	(in thousands)	
Prepaid pension costs	$—	$11,533
Other regulatory assets, deferred	145,815	75,280
Current liabilities, other	(1,307)	(1,183)
Employee benefit obligations	(54,487)	(20,039)

Presented below are the amounts included in regulatory assets at December 31, 2014 and 2013 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 2015.

	2014	2013	Estimated Amortization in 2015
	(in thousands)		
Prior service cost	$3,286	$4,401	$1,115
Net (gain) loss	142,529	70,879	9,281
Regulatory assets	$145,815	$75,280	

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The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2014 and 2013 are presented in the following table:

	2014	2013
	(in thousands)	
Regulatory assets:		
Beginning balance	$75,280	$139,261
Net (gain) loss	76,209	(54,432)
Reclassification adjustments:		
Amortization of prior service costs	(1,115)	(1,164)
Amortization of net gain (loss)	(4,559)	(8,385)
Total reclassification adjustments	(5,674)	(9,549)
Total change	70,535	(63,981)
Ending balance	$145,815	$75,280

Components of net periodic pension cost were as follows:

	2014	2013	2012
	(in thousands)		
Service cost	$10,181	$11,128	$9,101
Interest cost	19,433	17,321	17,199
Expected return on plan assets	(28,468)	(26,435)	(25,932)
Recognized net (gain) loss	4,559	8,385	3,913
Net amortization	1,115	1,164	1,262
Net periodic pension cost	$6,820	$11,563	$5,543

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, 2014, estimated benefit payments were as follows:

	Benefit Payments (in thousands)
2015	$ 22,002
2016	18,683
2017	19,950
2018	21,019
2019	22,229
2020 to 2024	129,877

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Other Postretirement Benefits
Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2014 and 2013 were as follows:

	2014	2013
	(in thousands)	
Change in benefit obligation		
Benefit obligation at beginning of year	$68,579	$75,395
Service cost	1,163	1,355
Interest cost	3,235	2,982
Benefits paid	(4,061)	(3,583)
Actuarial (gain) loss	11,317	(7,900)
Plan amendment	(2,089)	—
Retiree drug subsidy	357	330
Balance at end of year	78,501	68,579
Change in plan assets		
Fair value of plan assets at beginning of year	17,474	16,227
Actual return on plan assets	1,578	2,119
Employer contributions	2,846	2,381
Benefits paid	(3,704)	(3,253)
Fair value of plan assets at end of year	18,194	17,474
Accrued liability	$(60,307)	$(51,105)

Amounts recognized in the balance sheets at December 31, 2014 and 2013 related to the Company's other postretirement benefit plans consist of the following:

	2014	2013
	(in thousands)	
Other regulatory assets, deferred	$6,100	$—
Current liabilities, other	(639)	(687)
Other regulatory liabilities, deferred	(4,290)	(6,984)
Employee benefit obligations	(59,668)	(50,418)

Presented below are the amounts included in net regulatory assets (liabilities) at December 31, 2014 and 2013 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 2015.

	2014	2013	Estimated Amortization in 2015
	(in thousands)		
Prior service cost	$(2,137)	$138	$25
Net (gain) loss	3,947	(7,122)	—
Net regulatory assets (liabilities)	$1,810	$(6,984)	

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The changes in the balance of net regulatory assets (liabilities) related to the other postretirement benefit plans for the plan years ended December 31, 2014 and 2013 are presented in the following table:

	2014	2013
	(in thousands)	
Net regulatory assets (liabilities):		
Beginning balance	$(6,984)	$2,169
Net (gain) loss	11,045	(8,967)
Change in prior service costs	(2,089)	—
Reclassification adjustments:		
Amortization of prior service costs	(186)	(186)
Amortization of net gain (loss)	24	—
Total reclassification adjustments	(162)	(186)
Total change	8,794	(9,153)
Ending balance	$1,810	$(6,984)

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

	2014	2013	2012
	(in thousands)		
Service cost	$1,163	$1,355	$1,167
Interest cost	3,235	2,982	3,367
Expected return on plan assets	(1,306)	(1,238)	(1,311)
Net amortization	162	186	379
Net periodic postretirement benefit cost	$3,254	$3,285	$3,602

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

	Benefit Payments	Subsidy Receipts	Total
	(in thousands)		
2015	$4,694	$(431)	$4,263
2016	4,982	(480)	4,502
2017	5,136	(535)	4,601
2018	5,300	(594)	4,706
2019	5,326	(660)	4,666
2020 to 2024	27,399	(3,430)	23,969

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. The Company's investment policies for both the pension plan and the other postretirement benefit plans cover a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily to gain efficient exposure to the various asset classes and as hedging tools. The Company minimizes the risk of large losses primarily through diversification but also monitors and manages other aspects of risk.

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The composition of the Company's pension plan and other postretirement benefit plan assets as of December 31, 2014 and 2013, along with the targeted mix of assets for each plan, is presented below:

	Target		2014		2013	
Pension plan assets:						
Domestic equity	26	%	30	%	31	%
International equity	25		23		25	
Fixed income	23		27		23	
Special situations	3		1		1	
Real estate investments	14		14		14	
Private equity	9		5		6	
Total	100	%	100	%	100	%
Other postretirement benefit plan assets:						
Domestic equity	25	%	29	%	30	%
International equity	24		22		24	
Domestic fixed income	25		29		25	
Special situations	3		1		1	
Real estate investments	14		14		14	
Private equity	9		5		6	
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.
- 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, 2014 and 2013. 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

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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.
- 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, 2014 and 2013 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, 2014:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in thousands)			
Assets:				
Domestic equity*	$76,460	$31,588	$—	$108,048
International equity*	47,988	44,223	—	92,211
Fixed income:				
U.S. Treasury, government, and agency bonds	—	31,372	—	31,372
Mortgage- and asset-backed securities	—	8,438	—	8,438
Corporate bonds	—	50,931	—	50,931
Pooled funds	—	23,063	—	23,063
Cash equivalents and other	130	29,597	—	29,727
Real estate investments	13,154	—	50,281	63,435
Private equity	—	—	25,573	25,573
Total	$137,732	$219,212	$75,854	$432,798
Liabilities:				
Derivatives	$(87)	$—	$—	$(87)
Total	$137,645	$219,212	$75,854	$432,711

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

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As of December 31, 2013:	Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in thousands)			
Assets:				
Domestic equity*	$63,269	$37,037	$—	$100,306
International equity*	48,606	44,941	—	93,547
Fixed income:				
U.S. Treasury, government, and agency bonds	—	26,461	—	26,461
Mortgage- and asset-backed securities	—	6,873	—	6,873
Corporate bonds	—	43,222	—	43,222
Pooled funds	—	20,810	—	20,810
Cash equivalents and other	38	9,851	—	9,889
Real estate investments	11,493	—	44,139	55,632
Private equity	—	—	25,201	25,201
Total	$123,406	$189,195	$69,340	$381,941
Liabilities:				
Derivatives	$—	$(115)	$—	$(115)
Total	$123,406	$189,080	$69,340	$381,826

* 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, 2014 and 2013 were as follows:

	2014 Real Estate Investments	Private Equity	2013 Real Estate Investments	Private Equity
	(in thousands)			
Beginning balance	$44,139	$25,201	$37,039	$26,129
Actual return on investments:				
Related to investments held at year end	4,263	2,697	3,357	376
Related to investments sold during the year	1,488	(727)	1,310	2,282
Total return on investments	5,751	1,970	4,667	2,658
Purchases, sales, and settlements	391	(1,598)	2,433	(3,586)
Ending balance	$50,281	$25,573	$44,139	$25,201

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The fair values of other postretirement benefit plan assets as of December 31, 2014 and 2013 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, 2014:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in thousands)			
Assets:				
Domestic equity*	$3,105	$1,283	$—	$4,388
International equity*	1,949	1,798	—	3,747
Fixed income:				
U.S. Treasury, government, and agency bonds	—	1,274	—	1,274
Mortgage- and asset-backed securities	—	342	—	342
Corporate bonds	—	2,071	—	2,071
Pooled funds	—	937	—	937
Cash equivalents and other	510	1,203	—	1,713
Real estate investments	534	—	2,042	2,576
Private equity	—	—	1,039	1,039
Total	$6,098	$8,908	$3,081	$18,087
Liabilities:				
Derivatives	$(4)	$—	$—	$(4)
Total	$6,094	$8,908	$3,081	$18,083

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

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As of December 31, 2013:	Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1) (in thousands)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
Assets:				
Domestic equity*	$2,778	$1,628	$—	$4,406
International equity*	2,136	1,973	—	4,109
Fixed income:				
U.S. Treasury, government, and agency bonds	—	1,161	—	1,161
Mortgage- and asset-backed securities	—	303	—	303
Corporate bonds	—	1,897	—	1,897
Pooled funds	—	1,417	—	1,417
Cash equivalents and other	1	433	—	434
Real estate investments	504	—	1,939	2,443
Private equity	—	—	1,108	1,108
Total	$5,419	$8,812	$3,047	$17,278
Liabilities:				
Derivatives	$—	$(5)	$—	$(5)
Total	$5,419	$8,807	$3,047	$17,273

* 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, 2014 and 2013 were as follows:

	2014 Real Estate Investments (in thousands)	2014 Private Equity	2013 Real Estate Investments	2013 Private Equity
Beginning balance	$1,939	$1,108	$1,667	$1,155
Actual return on investments:				
Related to investments held at year end	27	26	108	16
Related to investments sold during the year	60	(30)	57	104
Total return on investments	87	(4)	165	120
Purchases, sales, and settlements	16	(65)	107	(167)
Ending balance	$2,042	$1,039	$1,939	$1,108

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides an 85% matching contribution on up to 6% of an employee's base salary. Total matching contributions made to the plan for 2014, 2013, and 2012 were $4.2 million, $4.1 million, and $4.0 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of

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

Environmental Matters

New Source Review Actions

As part of a nationwide enforcement initiative against the electric utility industry which began in 1999, the EPA brought civil enforcement actions in federal district court against Georgia Power alleging violations of the New Source Review (NSR) provisions of the Clean Air Act at certain coal-fired electric generating units, including a unit co-owned by the Company. These civil actions seek penalties and injunctive relief, including orders requiring installation of the best available control technologies at the affected units. These actions were filed concurrently with the issuance of notices of violation of the NSR provisions to the Company with respect to the Company's Plant Crist. The case against Georgia Power (including claims related to a unit co-owned by the Company) has been administratively closed in the U.S. District Court for the Northern District of Georgia since 2001.

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

Environmental Remediation

The Company must comply with environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company may also incur substantial costs to clean up properties. The Company received authority from the Florida PSC to recover approved environmental compliance costs through the environmental cost recovery clause. The Florida PSC reviews costs and adjusts rates up or down annually.

The Company recognizes a liability for environmental remediation costs only when it determines a loss is probable. At December 31, 2014, the Company's environmental remediation liability included estimated costs of environmental remediation projects of approximately $48.3 million. For 2014, approximately $4.5 million was included in under recovered regulatory clause revenues and other current liabilities, and approximately $43.7 million was included in other regulatory assets, deferred and other deferred credits and liabilities. These estimated costs relate to site closure criteria by the Florida Department of Environmental Protection (FDEP) for potential impacts to soil and groundwater from herbicide applications at the Company's substations. The schedule for completion of the remediation projects is subject to FDEP approval. The projects have been approved by the Florida PSC for recovery through the Company's environmental cost recovery clause; therefore, these liabilities have no impact on net income.

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

Retail Regulatory Matters

The Company's rates and charges for service to retail customers are subject to the regulatory oversight of the Florida PSC. The Company's rates are a combination of base rates and several separate cost recovery clauses for specific categories of costs. These separate cost recovery clauses address such items as fuel and purchased energy costs, purchased power capacity costs, energy conservation and demand side management programs, and the costs of compliance with environmental laws and regulations. Costs not addressed through one of the specific cost recovery clauses are recovered through the Company's base rates.

Retail Base Rate Case

In December 2013, the Florida PSC voted to approve the Settlement Agreement among the Company and all of the intervenors to the docketed proceeding with respect to the Company's request to increase retail base rates. Under the terms of the Settlement Agreement, the Company (1) increased base rates designed to produce an additional $35 million in annual revenues effective January 2014 and subsequently increased base rates designed to produce an additional $20 million in annual revenues effective January 2015; (2)

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continued its current authorized retail ROE midpoint (10.25%) and range (9.25% – 11.25%); and (3) will accrue a return similar to AFUDC on certain transmission system upgrades placed into service after January 2014 until the next base rate adjustment date or January 1, 2017, whichever comes first.

The 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 Settlement Agreement also provides that the Company may reduce depreciation expense and record a regulatory asset that will be included as an offset to the other cost of removal regulatory liability in an aggregate amount up to $62.5 million between January 2014 and June 2017. In any given month, such depreciation expense reduction may not exceed the amount necessary for the 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 the Company's next base rate case or next depreciation and dismantlement study proceeding, whichever comes first. As a result, the Company recognized an $8.4 million reduction in depreciation expense in 2014.

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

Cost Recovery Clauses

On October 22, 2014, the Florida PSC approved the Company's annual rate clause request for its fuel, purchased power capacity, environmental, and energy conservation cost recovery factors for 2015. The net effect of the approved changes is an expected $41.2 million increase in annual revenue for 2015. The increased revenues will not have a significant impact on net income since most of the revenues will be offset by expenses.

Revenues for all cost recovery clauses, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor for fuel and purchased power will have no significant effect on the Company's revenues or net income, but will affect annual cash flow. The recovery provisions for environmental compliance and energy conservation include related expenses and a return on net average investment.

Retail Fuel Cost Recovery

The Company has established fuel cost recovery rates as approved by the Florida PSC. If, at any time during the year, the projected year-end fuel cost over or under recovery balance exceeds 10% of the projected fuel revenue applicable for the period, the Company is required to notify the Florida PSC and indicate if an adjustment to the fuel cost recovery factor is being requested. The Company filed such notice with the Florida PSC on July 18, 2014, but no adjustment to the factor was requested for 2014.

At December 31, 2014 and 2013, the under recovered fuel balance was approximately $39.9 million and $21.0 million, respectively, which is included in under recovered regulatory clause revenues in the balance sheets.

Purchased Power Capacity Recovery

The Company has established purchased power capacity recovery cost rates as approved by the Florida PSC. If the projected year-end purchased power capacity cost over or under recovery balance exceeds 10% of the projected purchased power capacity revenue applicable for the period, the Company is required to notify the Florida PSC and indicate if an adjustment to the purchased power capacity cost recovery factor is being requested.

At December 31, 2014 and 2013, the under recovered purchased power capacity balance was approximately $0.3 million and $2.8 million, respectively, which is included in under recovered regulatory clause revenues in the balance sheets.

Environmental Cost Recovery

The Florida Legislature adopted legislation for an environmental cost recovery clause, which allows an electric utility to petition the Florida PSC for recovery of prudent environmental compliance costs that are not being recovered through base rates or any other recovery mechanism. Such environmental costs include operations and maintenance expenses, emissions allowance expense, depreciation, and a return on net average investment. This legislation also allows recovery of costs incurred as a result of an agreement between the Company and the FDEP for the purpose of ensuring compliance with ozone ambient air quality standards adopted by the EPA.

In 2007, the Florida PSC voted to approve a stipulation among the Company, the Office of Public Counsel, and the Florida Industrial Power Users Group regarding the Company's plan for complying with certain federal and state regulations addressing air quality. The Company's environmental compliance plan as filed in 2007 contemplated implementation of specific projects identified in the plan

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from 2007 through 2018. The Florida PSC's approval of the stipulation also required the Company to file annual updates to the plan and outlined a process for approval of additional elements in the plan when they became committed projects. In the 2010 update filing, the Company identified several elements of the updated plan that the Company had decided to implement. Following the process outlined in the original approved stipulation, these additional projects were approved by the Florida PSC later in 2010. The Florida PSC acknowledged that the costs of the approved projects associated with the Company's Clean Air Interstate Rule and Clean Air Visibility Rule compliance plans are eligible for recovery through the environmental cost recovery clause.
Annually, the Company seeks recovery of projected costs including any true-up amounts from prior periods. At December 31, 2014 and 2013, the under recovered environmental balance was approximately $9.8 million and $14.4 million, respectively, which is included in under recovered regulatory clause revenues in the balance sheets.
In 2012, the Mississippi PSC approved Mississippi Power's request for a certificate of public convenience and necessity to construct a scrubber on Plant Daniel Units 1 and 2. These units are jointly owned by Mississippi Power and the Company, with 50% ownership each. The estimated total cost of the project is approximately $660 million, with the Company's portion being $330 million, excluding AFUDC, and it is scheduled for completion in December 2015. The Company's portion of the cost is expected to be recovered through the environmental cost recovery clause. On August 28, 2014, the Chancery Court of Harrison County, Mississippi dismissed an appeal by the Sierra Club related to the construction of the scrubber on Plant Daniel Units 1 and 2.

Energy Conservation Cost Recovery

Every five years, the Florida PSC establishes new numeric conservation goals covering a 10-year period for utilities to reduce annual energy and seasonal peak demand using demand-side management (DSM) programs. After the goals are established, utilities develop plans and programs to meet the approved goals. The costs for these programs are recovered through rates established annually in the energy conservation cost recovery (ECCR) clause.
At December 31, 2014 and 2013, the under recovered energy conservation balance was approximately $2.6 million and $7.0 million, respectively, which is included in under recovered regulatory clause revenues in the balance sheets.

4. JOINT OWNERSHIP AGREEMENTS

The Company and Mississippi Power jointly own Plant Daniel Units 1 and 2, which together represent capacity of 1,000 MWs. Plant Daniel is a generating plant located in Jackson County, Mississippi. In accordance with the operating agreement, Mississippi Power acts as the Company's agent with respect to the construction, operation, and maintenance of these units.
The Company and Georgia Power jointly own the 818 MWs capacity Plant Scherer Unit 3. Plant Scherer is a generating plant located near Forsyth, Georgia. In accordance with the operating agreement, Georgia Power acts as the Company's agent with respect to the construction, operation, and maintenance of the unit.
At December 31, 2014, the Company's percentage ownership and investment in these jointly-owned facilities were as follows:

	Plant Scherer Unit 3 (coal)	Plant Daniel Units 1 & 2 (coal)
	(in thousands)	
Plant in service	$387,511 [(a)]	$285,834
Accumulated depreciation	130,069	177,304
Construction work in progress	2,912	286,343
Company Ownership	25 %	50 %

(a) Includes net plant acquisition adjustment of $1.8 million.

The Company's proportionate share of its plant operating expenses is included in the corresponding operating expenses in the statements of income and the Company is responsible for providing its own financing.

5. INCOME TAXES

On behalf of the Company, Southern Company files a consolidated federal income tax return and combined state income tax returns for the States of Alabama, Georgia, and Mississippi. In addition, the Company files a separate company income tax return for the State of Florida. Under a joint consolidated income tax allocation agreement, each 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.

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

	2014	2013	2012
	(in thousands)		
Federal -			
Current	$22,771	$5,009	$(92,610)
Deferred	52,602	63,134	161,096
	75,373	68,143	68,486
State -			
Current	(39)	(2,410)	(2,484)
Deferred	12,728	13,935	13,209
	12,689	11,525	10,725
Total	$88,062	$79,668	$79,211

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:

	2014	2013
	(in thousands)	
Deferred tax liabilities-		
Accelerated depreciation	$776,953	$721,087
Property basis differences	52,242	45,960
Fuel recovery clause	16,148	7,972
Pension and other employee benefits	34,405	25,800
Regulatory assets associated with employee benefit obligations	59,788	27,660
Regulatory assets associated with asset retirement obligations	6,768	6,554
Other	21,712	23,947
Total	968,016	858,980
Deferred tax assets-		
Federal effect of state deferred taxes	30,587	24,277
Postretirement benefits	18,033	17,816
Pension and other employee benefits	65,506	33,015
Property reserve	13,440	15,144
Asset retirement obligations	6,768	6,554
Alternative minimum tax carryforward	18,200	18,420
Other	18,893	17,780
Total	171,427	133,006
Net deferred tax liabilities	796,589	725,974
Portion included in current assets/(liabilities), net	3,134	8,381
Accumulated deferred income taxes	$799,723	$734,355

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

At December 31, 2014, tax-related regulatory assets to be recovered from customers were $56.3 million. These assets are primarily attributable to tax benefits flowed through to customers in prior years, deferred taxes previously recognized at rates lower than the current enacted tax law, and taxes applicable to capitalized interest.

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At December 31, 2014, the tax-related regulatory liabilities to be credited to customers were $3.9 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 average life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $1.3 million in 2014 and $1.4 million in both 2013 and 2012. At December 31, 2014, all ITCs available to reduce federal income taxes payable had been utilized.

Effective Tax Rate

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

	2014	2013	2012
Federal statutory rate	35.0%	35.0%	35.0%
State income tax, net of federal deduction	3.5	3.5	3.3
Non-deductible book depreciation	0.4	0.5	0.5
Differences in prior years' deferred and current tax rates	(0.1)	(0.2)	(0.2)
AFUDC equity	(1.8)	(1.1)	(0.9)
Other, net	0.1	(0.1)	(0.2)
Effective income tax rate	37.1%	37.6%	37.5%

The decrease in the Company's 2014 effective tax rate is primarily the result of an increase in AFUDC equity which is not taxable.

Unrecognized Tax Benefits

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

	2014	2013	2012
	(in thousands)		
Unrecognized tax benefits at beginning of year	$45	$5,007	$2,892
Tax positions increase from current periods	46	45	2,630
Tax positions increase/(decrease) from prior periods	(45)	(5,007)	515
Reductions due to settlements	—	—	(1,030)
Balance at end of year	$46	$45	$5,007

The tax positions increase from current periods and decrease from prior periods for 2014 relate primarily to the research and development credit. The tax positions decrease from prior periods for 2013 relate primarily to the tax accounting method change for repairs related to generation assets. See "Tax Method of Accounting for Repairs" herein for additional information.

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

	2014	2013	2012
	(in thousands)		
Tax positions impacting the effective tax rate	$46	$45	$45
Tax positions not impacting the effective tax rate	—	—	4,962
Balance of unrecognized tax benefits	$46	$45	$5,007

The tax positions impacting the effective tax rate for all periods presented relate primarily to the research and development credit. The tax positions not impacting the effective tax rate for 2012 relate to the tax accounting method change for repairs related to generation assets. These amounts are presented on a gross basis without considering the related federal or state income tax impact.

The Company classifies interest on tax uncertainties as interest expense. Accrued interest for unrecognized tax benefits was immaterial for all periods presented. The Company did not accrue any penalties on uncertain tax positions.

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

The IRS has finalized its audits of Southern Company's consolidated federal income tax returns through 2012. Southern Company has filed its 2013 federal income tax return and has received a partial acceptance letter from the IRS; however, the IRS has not finalized its audit. Southern Company is a participant in the Compliance Assurance Process of the IRS. The audits for the Company's state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2010.

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, in April 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. In September 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 continues to review this guidance; however, these regulations are not expected to have a material impact on the Company's financial statements.

6. FINANCING

Securities Due Within One Year

At December 31, 2014, the Company had no scheduled maturities of long-term debt due within one year.

Maturities from 2016 through 2019 applicable to total long-term debt are as follows: $110 million in 2016 and $85 million in 2017. There are no scheduled maturities in 2015, 2018, or 2019.

Senior Notes

At each of December 31, 2014 and 2013, the Company had a total of $1.07 billion and $945 million of senior notes outstanding, respectively. These senior notes are effectively subordinate to all secured debt of the Company, which totaled approximately $41 million at December 31, 2014.

In September 2014, the Company issued $200 million aggregate principal amount of Series 2014A 4.55% Senior Notes due October 1, 2044. The proceeds were used to repay a portion of the Company's outstanding short-term indebtedness, for general corporate purposes, including the Company's continuous construction program and for repayment at maturity $75 million aggregate principal amount of the Company's Series K 4.90% Senior Notes due October 1, 2014.

Pollution Control Revenue Bonds

Pollution control obligations represent loans to the Company from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control and solid waste disposal facilities. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. The amount of tax-exempt pollution control revenue bonds outstanding at December 31, 2014 and 2013 was $309 million and $296 million, respectively.

In April 2014, the Company executed a loan agreement with Mississippi Business Finance Corporation (MBFC) related to MBFC's issuance of $29.075 million aggregate principal amount of Pollution Control Revenue Refunding Bonds, First Series 2014 (Gulf Power Company Project) due April 1, 2044 for the benefit of the Company. The proceeds were used to redeem $29.075 million aggregate principal amount of MBFC Pollution Control Revenue Refunding Bonds, Series 2003 (Gulf Power Company Project).

In June 2014, the Company reoffered to the public $13 million aggregate principal amount of MBFC Solid Waste Disposal Facilities Revenue Refunding Bonds, Series 2012 (Gulf Power Company Project), which had been previously purchased and held by the Company since December 2013.

Outstanding Classes of Capital Stock

The Company currently has preferred stock, Class A preferred stock, preference stock, and common stock authorized. The Company's preferred stock and Class A preferred stock, without preference between classes, rank senior to the Company's preference stock and common stock with respect to payment of dividends and voluntary or involuntary dissolution. No shares of

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preferred stock or Class A preferred stock were outstanding at December 31, 2014. The Company's preference stock ranks senior to the common stock with respect to the payment of dividends and voluntary or involuntary dissolution. Certain series of the preference stock are subject to redemption at the option of the Company on or after a specified date (typically five or 10 years after the date of issuance) at a redemption price equal to 100% of the liquidation amount of the preference stock. In addition, certain series of the preference stock may be redeemed earlier at a redemption price equal to 100% of the liquidation amount plus a make-whole premium based on the present value of the liquidation amount and future dividends.

In January 2014, the Company issued 500,000 shares of common stock to Southern Company and realized proceeds of $50 million. The proceeds were used to repay a portion of the Company's short-term debt and for other general corporate purposes, including the Company's continuous construction program.

Subsequent to December 31, 2014, the Company issued 200,000 shares of common stock to Southern Company and realized proceeds of $20 million. The proceeds were used to repay a portion of the Company's short-term debt and for other general corporate purposes, including the Company's continuous construction program.

Dividend Restrictions

The Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

Assets Subject to Lien

The Company has granted a lien on its property at Plant Daniel in connection with the issuance of two series of pollution control revenue bonds with an outstanding principal amount of $41 million. There are no agreements or other arrangements among the Southern Company system companies under which the assets of one company have been pledged or otherwise made available to satisfy obligations of Southern Company or any of its subsidiaries.

Bank Credit Arrangements

At December 31, 2014, committed credit arrangements with banks were as follows:

Expires					Executable Term-Loans		Due Within One Year	
2015	2016	2017	Total	Unused	One Year	Two Years	Term Out	No Term Out
			(in millions)					
$80	$165	$30	$275	$275	$50	$—	$50	$30

Subject to applicable market conditions, the Company expects to renew its bank credit arrangements as needed, prior to expiration. Most of the $275 million of unused credit arrangements with banks provide liquidity support to the Company's variable rate pollution control revenue bonds and commercial paper program. The Company had $69 million of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2014. In addition, at December 31, 2014, the Company had $78 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months. Most of the bank credit arrangements require payment of commitment fees based on the unused portion of the commitments. Commitment fees average less than 1/4 of 1% for the Company.

Most of these bank credit arrangements contain covenants that limit the Company's debt level to 65% of total capitalization, as defined in the arrangements. For purposes of these definitions, debt excludes certain hybrid securities. At December 31, 2014, the Company was in compliance with these covenants.

For short-term cash needs, the Company borrows primarily through a commercial paper program that has the liquidity support of the Company's committed bank credit arrangements described above. The Company may also borrow through various other arrangements with banks. Commercial paper and short-term bank loans are included in notes payable in the balance sheets.

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Details of short-term borrowings were as follows:

	Commercial Paper at the End of the Period	
	Amount Outstanding	Weighted Average Interest Rate
	(in millions)	
December 31, 2014	$110	0.3%
December 31, 2013	$136	0.2%

7. COMMITMENTS

Fuel and Purchased Power Agreements

To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement and delivery of fossil fuel which are not recognized on the balance sheets. In 2014, 2013, and 2012, the Company incurred fuel expense of $604.6 million, $532.8 million, and $544.9 million, respectively, the majority of which was purchased under long-term commitments. The Company expects that a substantial amount of its future fuel needs will continue to be purchased under long-term commitments.

In addition, the Company has entered into various long-term commitments for the purchase of capacity, energy, and transmission, some of which are accounted for as operating leases. The energy-related costs associated with PPAs are recovered through the fuel cost recovery clause. The capacity and transmission-related costs associated with PPAs are recovered through the purchased power capacity cost recovery clause. Capacity expense under purchased power agreements accounted for as operating leases was $49.5 million, $21.3 million, and $24.6 million for 2014, 2013, and 2012, respectively.

Estimated total minimum long-term commitments at December 31, 2014 were as follows:

	Operating Lease PPAs
	(in millions)
2015	$78.7
2016	78.7
2017	78.8
2018	78.9
2019	78.9
2020 and thereafter	270.3
Total	$664.3

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and all of the other traditional operating companies and Southern Power. Under these agreements, each of the traditional operating companies and Southern Power may be jointly and severally liable. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the other traditional operating companies to ensure the Company will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power as a contracting party under these agreements.

Operating Leases

In addition to the operating lease PPAs discussed above, the Company has other operating lease agreements with various terms and expiration dates. Total rent expense was $15.0 million, $18.0 million, and $20.1 million for 2014, 2013, and 2012, respectively.

Estimated total minimum lease payments under these operating leases at December 31, 2014 were as follows:

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	Minimum Lease Payments		
	Barges & Railcars	Other	Total
	(in millions)		
2015	$15.1	$0.1	$15.2
2016	15.0	0.1	15.1
2017	1.4	0.1	1.5
Total	$31.5	$0.3	$31.8

The Company and Mississippi Power jointly entered into an operating lease agreement for aluminum railcars for the transportation of coal to Plant Daniel. The Company has the option to purchase the railcars at the greater of lease termination value or fair market value or to renew the leases at the end of each lease term. The Company and Mississippi Power also have separate lease agreements for other railcars that do not include purchase options. The Company's share of the lease costs, charged to fuel inventory and recovered through the retail fuel cost recovery clause, was $2.8 million in 2014, $3.1 million in 2013, and $3.6 million in 2012. The Company's annual railcar lease payments for 2015 through 2017 will average approximately $1.6 million. The Company has no lease payment obligations for the period 2018 and thereafter.

8. STOCK COMPENSATION

Stock Options

Southern Company provides non-qualified stock options through its Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. As of December 31, 2014, there were 195 current and former employees of the Company 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. The Company generally recognizes stock option expense on a straight-line basis over the vesting period which equates to the requisite service period; however, for employees who are eligible for retirement, the total cost is expensed at the grant date. Options outstanding will expire no later than 10 years after the date of grant, unless terminated earlier by the Southern Company Board of Directors in accordance with the Omnibus Incentive Compensation Plan. Stock options held by employees of a company undergoing a change in control vest upon the change in control.

For the years ended December 31, 2014, 2013, and 2012, employees of the Company were granted stock options for 432,371 shares, 285,209 shares, and 244,607 shares, respectively. The weighted average grant-date fair value of stock options granted during 2014, 2013, and 2012, derived using the Black-Scholes stock option pricing model, was $2.20, $2.93, and $3.39, respectively.

The compensation cost and tax benefits related to the grant of Southern Company stock options to the Company's employees and the exercise of stock options are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. No cash proceeds are received by the Company upon the exercise of stock options. The amounts were not material for any year presented. As of December 31, 2014, the amount of unrecognized compensation cost related to stock option awards not yet vested was immaterial.

The total intrinsic value of options exercised during the years ended December 31, 2014, 2013, and 2012 was $5.2 million, $1.7 million, and $3.8 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $2.0 million, $0.6 million, and $1.5 million for the years ended December 31, 2014, 2013, and 2012, respectively. As of December 31, 2014, the aggregate intrinsic value for the options outstanding and options exercisable was $11.9 million and $7.7 million, respectively.

Performance Shares

Southern Company provides performance share award units through its Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. The performance share units granted under the plan vest at the end of a three-year performance period which equates to the requisite service period. Employees that retire prior to the end of the three-year period receive a pro rata number of shares, issued at the end of the performance period, based on actual months of service prior to retirement. The value of the award units is based on Southern Company's total shareholder return (TSR) over the three-year performance period which measures Southern Company's relative performance against a group of industry peers. The performance shares are delivered in common stock following the end of the performance period based on

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Southern Company's actual TSR and may range from 0% to 200% of the original target performance share amount. Performance share units held by employees of a company undergoing a change in control vest upon the change in control.
For the years ended December 31, 2014, 2013, and 2012, employees of the Company were granted performance share units of 37,829, 30,627, and 29,444, respectively. The weighted average grant-date fair value of performance share units granted during 2014, 2013, and 2012, determined using a Monte Carlo simulation model to estimate the TSR of Southern Company's stock among the industry peers over the performance period, was $37.54, $40.50, and $41.99, respectively.
The Company recognizes compensation expense on a straight-line basis over the three-year performance period without remeasurement. Compensation expense for awards where the service condition is met is recognized regardless of the actual number of shares issued. For the years ended December 31, 2014, 2013, and 2012, total compensation cost for performance share units recognized in income was approximately $1.0 million annually, with the related tax benefit also recognized in income of $0.4 million annually. The compensation cost and tax benefits related to the grant of Southern Company performance share units to the Company's employees are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. As of December 31, 2014, there was $1.3 million of total unrecognized compensation cost related to performance share award units that will be recognized over a weighted-average period of approximately 20 months.
9. FAIR VALUE MEASUREMENTS
Fair value measurements are based on inputs of observable and unobservable market data that a market participant would use in pricing the asset or liability. The use of observable inputs is maximized where available and the use of unobservable inputs is minimized for fair value measurement and reflects a three-tier fair value hierarchy that prioritizes inputs to valuation techniques used for fair value measurement.

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

In the case of multiple inputs being used in a fair value measurement, the lowest level input that is significant to the fair value measurement represents the level in the fair value hierarchy in which the fair value measurement is reported.
As of December 31, 2014, 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, 2014:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in thousands)			
Assets:				
Energy-related derivatives	$—	$125	$—	$125
Cash equivalents	18,032	—	—	18,032
Total	$18,032	$125	$—	$18,157
Liabilities:				
Energy-related derivatives	$—	$72,435	$—	$72,435

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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 thousands)			
Assets:				
Energy-related derivatives	$—	$6,962	$—	$6,962
Cash equivalents	15,929	—	—	15,929
Total	$15,929	$6,962	$—	$22,891
Liabilities:				
Energy-related derivatives	$—	$17,043	$—	$17,043

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. See Note 10 for additional information on how these derivatives are used.

As of December 31, 2014 and 2013, 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, 2014:	(in thousands)			
Cash equivalents:				
Money market funds	$18,032	None	Daily	Not applicable
As of December 31, 2013:				
Cash equivalents:				
Money market funds	$15,929	None	Daily	Not applicable

The money market funds are short-term investments of excess funds in various money market mutual funds, which are portfolios of short-term debt securities. The money market funds are regulated by the SEC and typically receive the highest rating from credit rating agencies. Regulatory and rating agency requirements for money market funds include minimum credit ratings and maximum maturities for individual securities and a maximum weighted average portfolio maturity. Redemptions are available on a same day basis up to the full amount of the Company's investment in the money market funds.

As of December 31, 2014 and 2013, other financial instruments for which the carrying amount did not equal fair value were as follows:

	Carrying Amount	Fair Value
	(in thousands)	
Long-term debt:		
2014	$1,369,594	$1,476,954
2013	$1,233,163	$1,261,889

The fair values are determined using Level 2 measurements and are based on quoted market prices for the same or similar issues or on the current rates offered to the Company.

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10. DERIVATIVES

The Company is exposed to market risks, primarily commodity price risk and interest rate risk. To manage the volatility attributable to these exposures, the Company nets its exposures, where possible, to take advantage of natural offsets and may enter into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a gross basis. See Note 9 for additional information. In the statements of cash flows, the cash impacts of settled energy-related and interest rate derivatives are recorded as operating activities.

Energy-Related Derivatives

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, the Company has limited exposure to market volatility in commodity fuel prices and prices of electricity. The Company manages fuel-hedging programs, implemented per the guidelines of the Florida PSC, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility.

To mitigate residual risks relative to movements in electricity prices, the Company may enter into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market. To mitigate residual risks relative to movements in gas prices, the Company may enter into fixed-price contracts for natural gas purchases; however, a significant portion of contracts are priced at market.

Energy-related derivative contracts are accounted for in one of two methods:

- Regulatory Hedges — Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the Company's fuel-hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the fuel cost recovery clause.
- Not Designated — Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

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

At December 31, 2014, the net volume of energy-related derivative contracts for natural gas positions totaled 84.59 million mmBtu for the Company, with the longest hedge date of 2019 over which it is hedging its exposure to the variability in future cash flows for forecasted transactions.

Interest Rate Derivatives

The Company may also enter into interest rate derivatives to hedge exposure to changes in interest rates. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings. The derivatives employed as hedging instruments are structured to minimize ineffectiveness, which is recorded directly to earnings.

At December 31, 2014, there were no interest rate derivatives outstanding.

The estimated pre-tax losses that will be reclassified from accumulated OCI to interest expense for the 12-month period ending December 31, 2015 are not material. The Company has deferred gains and losses that are expected to be amortized into earnings through 2020.

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Derivative Financial Statement Presentation and Amounts
At December 31, 2014 and 2013, the fair value of energy-related derivatives was reflected in the balance sheets as follows:

Derivative Category	Asset Derivatives Balance Sheet Location	2014	2013	Liability Derivatives Balance Sheet Location	2014	2013
		(in thousands)			(in thousands)	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	$34	$4,893	Liabilities from risk management activities	$36,922	$6,470
	Other deferred charges and assets	78	2,069	Other deferred credits and liabilities	35,502	10,573
Total derivatives designated as hedging instruments for regulatory purposes		$112	$6,962		$72,424	$17,043

Energy-related derivatives not designated as hedging instruments were immaterial on the balance sheets for 2014 and 2013.
The derivative contracts of the Company are not subject to master netting arrangements or similar agreements and are reported gross on the Company's financial statements. Some of these energy-related 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, 2014 and 2013 are presented in the following tables.

Fair Value

Assets	2014	2013	Liabilities	2014	2013
	(in thousands)			(in thousands)	
Energy-related derivatives presented in the Balance Sheet [(a)]	$125	$6,962	Energy-related derivatives presented in the Balance Sheet [(a)]	$72,435	$17,043
Gross amounts not offset in the Balance Sheet [(b)]	(123)	(5,775)	Gross amounts not offset in the Balance Sheet [(b)]	(123)	(5,775)
Net energy-related derivative assets	$2	$1,187	Net energy-related derivative liabilities	$72,312	$11,268

(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, 2014 and 2013, 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	2014	2013	Unrealized Gains Balance Sheet Location	2014	2013
		(in thousands)			(in thousands)	

Energy-related derivatives:	Other regulatory assets, current	$(36,922)	$(6,470)	Other regulatory liabilities, current	$34	$4,893
	Other regulatory assets, deferred	(35,502)	(10,573)	Other regulatory liabilities, deferred	78	2,069
Total energy-related derivative gains (losses)		$(72,424)	$(17,043)		$112	$6,962

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For the years ended December 31, 2014, 2013, and 2012, the pre-tax effects of interest rate derivatives designated as cash flow hedging instruments on the statements of income were as follows:

Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Recognized in OCI on Derivative (Effective Portion)			Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)			
					Amount		
Derivative Category	2014	2013	2012	Statements of Income Location	2014	2013	2012
	(in thousands)				(in thousands)		
Interest rate derivatives	$—	$—	$—	Interest expense, net of amounts capitalized	$(606)	$(769)	$(933)

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

For the years ended December 31, 2014, 2013, and 2012, the pre-tax effects of energy-related derivatives not designated as hedging instruments on the statements of income were not material.

Contingent Features

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain affiliated companies. At December 31, 2014, the Company's collateral posted with its derivative counterparties was not material.

At December 31, 2014, the fair value of derivative liabilities with contingent features was $20.5 million. However, because of joint and several liability features underlying these derivatives, the maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $54.5 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.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P or with counterparties who have posted collateral to cover potential credit exposure. The Company has also established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk. Therefore, the Company does not anticipate a material adverse effect on the financial statements as a result of counterparty nonperformance.

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11. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)
Summarized quarterly financial information for 2014 and 2013 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preference Stock
	(in thousands)		
March 2014	$407,132	$73,888	$36,743
June 2014	383,531	68,877	34,097
September 2014	438,334	88,600	46,547
December 2014	361,485	49,850	22,789
March 2013	$326,274	$51,640	$21,792
June 2013	371,173	69,151	32,582
September 2013	399,361	87,776	44,754
December 2013	343,493	56,436	25,301

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

SELECTED FINANCIAL AND OPERATING DATA 2010-2014
Gulf Power Company 2014 Annual Report

	2014	2013	2012	2011	2010
Operating Revenues (in thousands)	$1,590,482	$1,440,301	$1,439,762	$1,519,812	$1,590,209
Net Income After Dividends on Preference Stock (in thousands)	$140,176	$124,429	$125,932	$105,005	$121,511
Cash Dividends on Common Stock (in thousands)	$123,200	$115,400	$115,800	$110,000	$104,300
Return on Average Common Equity (percent)	11.02	10.30	10.92	9.55	11.69
Total Assets (in thousands)	$4,708,259	$4,337,571	$4,177,402	$3,871,881	$3,584,939
Gross Property Additions (in thousands)	$360,937	$304,778	$325,237	$337,830	$285,379
Capitalization (in thousands):					
Common stock equity	$1,309,590	$1,235,126	$1,180,742	$1,124,948	$1,075,036
Preference stock	146,504	146,504	97,998	97,998	97,998
Long-term debt	1,369,594	1,158,163	1,185,870	1,235,447	1,114,398
Total (excluding amounts due within one year)	$2,825,688	$2,539,793	$2,464,610	$2,458,393	$2,287,432
Capitalization Ratios (percent):					
Common stock equity	46.3	48.6	47.9	45.8	47.0
Preference stock	5.2	5.8	4.0	4.0	4.3
Long-term debt	48.5	45.6	48.1	50.2	48.7
Total (excluding amounts due within one year)	100.0	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	388,292	383,980	379,922	378,248	376,561
Commercial	54,892	54,567	53,808	53,450	53,263
Industrial	260	260	264	273	272
Other	603	582	577	565	562
Total	444,047	439,389	434,571	432,536	430,658
Employees (year-end)	1,384	1,410	1,416	1,424	1,330

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SELECTED FINANCIAL AND OPERATING DATA 2010-2014 (continued)
Gulf Power Company 2014 Annual Report

	2014	2013	2012	2011	2010
Operating Revenues (in thousands):					
Residential	$700,442	$632,495	$609,454	$637,352	$707,196
Commercial	408,401	395,062	389,936	408,389	439,468
Industrial	153,167	138,585	140,490	158,367	157,591
Other	4,530	3,858	4,591	4,382	4,471
Total retail	1,266,540	1,170,000	1,144,471	1,208,490	1,308,726
Wholesale — non-affiliates	129,151	109,386	106,881	133,555	109,172
Wholesale — affiliates	130,107	99,577	123,636	111,346	110,051
Total revenues from sales of electricity	1,525,798	1,378,963	1,374,988	1,453,391	1,527,949
Other revenues	64,684	61,338	64,774	66,421	62,260
Total	$1,590,482	$1,440,301	$1,439,762	$1,519,812	$1,590,209
Kilowatt-Hour Sales (in thousands):					
Residential	5,362,423	5,088,828	5,053,724	5,304,769	5,651,274
Commercial	3,838,148	3,809,939	3,858,521	3,911,399	3,996,502
Industrial	1,849,255	1,700,174	1,725,121	1,798,688	1,685,817
Other	25,236	20,946	25,267	25,430	25,602
Total retail	11,075,062	10,619,887	10,662,633	11,040,286	11,359,195
Wholesale — non-affiliates	1,670,121	1,162,308	977,395	2,012,986	1,675,079
Wholesale — affiliates	3,283,685	3,127,350	4,369,964	2,607,873	2,436,883
Total	16,028,868	14,909,545	16,009,992	15,661,145	15,471,157
Average Revenue Per Kilowatt-Hour (cents):					
Residential	13.06	12.43	12.06	12.01	12.51
Commercial	10.64	10.37	10.11	10.44	11.00
Industrial	8.28	8.15	8.14	8.80	9.35
Total retail	11.44	11.02	10.73	10.95	11.52
Wholesale	5.23	4.87	4.31	5.30	5.33
Total sales	9.52	9.25	8.59	9.28	9.88
Residential Average Annual Kilowatt-Hour Use Per Customer	13,865	13,301	13,303	14,028	15,036
Residential Average Annual Revenue Per Customer	$1,811	$1,653	$1,604	$1,685	$1,882
Plant Nameplate Capacity Ratings (year-end) (megawatts)	2,663	2,663	2,663	2,663	2,663
Maximum Peak-Hour Demand (megawatts):					
Winter	2,684	1,729	2,130	2,485	2,544
Summer	2,424	2,356	2,344	2,527	2,519
Annual Load Factor (percent)	51.1	55.9	56.3	54.5	56.1
Plant Availability Fossil-Steam (percent)*	89.4	92.8	82.5	84.7	94.7
Source of Energy Supply (percent):					
Coal	44.5	36.4	34.6	49.4	64.6
Gas	22.2	23.0	23.5	24.0	17.8
Purchased power —					
From non-affiliates	28.9	37.0	40.2	22.3	13.2
From affiliates	4.4	3.6	1.7	4.3	4.4

Total	100.0	100.0	100.0	100.0	100.0

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

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MISSISSIPPI POWER COMPANY
FINANCIAL SECTION

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Mississippi Power Company 2014 Annual Report

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

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2014.

/s/ G. Edison Holland, Jr.
G. Edison Holland, Jr.
Chairman, President, and Chief Executive Officer

/s/ Moses H. Feagin
Moses H. Feagin
Vice President, Chief Financial Officer, and Treasurer

March 2, 2015

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM
To the Board of Directors of
Mississippi Power Company

We have audited the accompanying balance sheets and statements of capitalization of Mississippi Power Company (the Company) (a wholly owned subsidiary of The Southern Company) as of December 31, 2014 and 2013, and the related statements of operations, comprehensive income (loss), common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2014. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements (pages II-387 to II-435) present fairly, in all material respects, the financial position of Mississippi Power Company as of December 31, 2014 and 2013, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America.
/s/ Deloitte & Touche LLP
Atlanta, Georgia
March 2, 2015

DEFINITIONS

Term	Meaning
2012 MPSC CPCN Order	A detailed order issued by the Mississippi PSC in April 2012 confirming the CPCN originally approved by the Mississippi PSC in 2010 authorizing acquisition, construction, and operation of the Kemper IGCC
AFUDC	Allowance for funds used during construction
Alabama Power	Alabama Power Company
APA	Asset purchase agreement
ASC	Accounting Standards Codification
Baseload Act	State of Mississippi legislation designed to enhance the Mississippi PSC's authority to facilitate development and construction of baseload generation in the State of Mississippi
CCR	Coal combustion residuals
Clean Air Act	Clean Air Act Amendments of 1990
CO_2	Carbon dioxide
CPCN	Certificate of public convenience and necessity
CWIP	Construction work in progress
DOE	U.S. Department of Energy
ECM	Energy cost management clause
ECO	Environmental compliance overview
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
GAAP	Generally accepted accounting principles
Georgia Power	Georgia Power Company
Gulf Power	Gulf Power Company
IGCC	Integrated coal gasification combined cycle
IRS	Internal Revenue Service
ITC	Investment tax credit
Kemper IGCC	IGCC facility under construction in Kemper County, Mississippi
KWH	Kilowatt-hour
LIBOR	London Interbank Offered Rate
Mirror CWIP	A regulatory liability account for use in mitigating future rate impacts for customers
mmBtu	Million British thermal units
Moody's	Moody's Investors Service, Inc.
MPUS	Mississippi Public Utilities Staff
MRA	Municipal and Rural Associations
MW	Megawatt
OCI	Other comprehensive income
PEP	Performance evaluation plan
Plant Daniel Units 3 and 4	Combined cycle Units 3 and 4 at Plant Daniel
power pool	The operating arrangement whereby the integrated generating resources of the traditional operating companies and Southern Power Company are subject to joint commitment and dispatch in order to serve their combined load obligations
PPA	Power purchase agreement
PSC	Public Service Commission
ROE	Return on equity
S&P	Standard and Poor's Rating Services, a division of The McGraw Hill Companies, Inc.
scrubber	Flue gas desulfurization system

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DEFINITIONS
(continued)

Term	Meaning
SCS	Southern Company Services, Inc. (the Southern Company system service company)
SEC	U.S. Securities and Exchange Commission
SMEPA	South Mississippi Electric Power Association
SouthernLINC Wireless	Southern Communications Services, Inc.
Southern Nuclear	Southern Nuclear Operating Company, Inc.
Southern Power	Southern Power Company and its subsidiaries
Southern Company system	The Southern Company, the traditional operating companies, Southern Power, Southern Electric Generating Company, Southern Nuclear, SCS, SouthernLINC Wireless, and other subsidiaries
SRR	System Restoration Rider
traditional operating companies	Alabama Power, Georgia Power, Gulf Power, and Mississippi Power Company

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Mississippi Power Company 2014 Annual Report
OVERVIEW
Business Activities
Mississippi Power Company (the Company) operates as a vertically integrated utility providing electricity to retail customers within its traditional service territory located within the State of Mississippi and to wholesale customers in the Southeast.
Many factors affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the Company's ability to maintain and grow energy sales and to maintain a constructive regulatory environment that provides timely recovery of prudently-incurred costs. These costs include those related to the completion and operation of major construction projects, primarily the Kemper IGCC and the Plant Daniel scrubber project, projected long-term demand growth, reliability, fuel, and increasingly stringent environmental standards, as well as ongoing capital expenditures required for maintenance. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future.
The Company's retail base rates are set under the PEP, a rate plan approved by the Mississippi PSC. PEP was designed with the objective to reduce the impact of rate changes on customers and provide incentives for the Company to keep customer prices low and customer satisfaction and reliability high.
In 2010, the Mississippi PSC issued a CPCN authorizing the acquisition, construction, and operation of the Kemper IGCC. The certificated cost estimate of the Kemper IGCC established by the Mississippi PSC was \$2.4 billion with a construction cost cap of \$2.88 billion, net of \$245.3 million of grants awarded to the project by the DOE under the Clean Coal Power Initiative Round 2 (DOE Grants) and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, AFUDC, and certain general exceptions, including change of law, force majeure, and beneficial capital (which exists when the Company demonstrates that the purpose and effect of the construction cost increase is to produce efficiencies that will result in a neutral or favorable effect on customers relative to the original proposal for the CPCN) (Cost Cap Exceptions).
The Company's current cost estimate for the Kemper IGCC in total is approximately \$6.20 billion, which includes approximately \$4.93 billion of costs subject to the construction cost cap. The Company does not intend to seek any rate recovery or 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. The Company has recorded pre-tax charges to income for revisions to the cost estimate of \$868.0 million (\$536.0 million after tax), \$1.10 billion (\$680.5 million after tax), and \$78.0 million (\$48.2 million after tax) in 2014, 2013 and 2012, respectively.
The Company placed the combined cycle and the associated common facilities portion of the Kemper IGCC project in service on August 9, 2014 and continues to focus on completing the remainder of the Kemper IGCC, including the gasifier and the gas clean-up facilities. The in-service date for the remainder of the Kemper IGCC is currently expected to occur in the first half of 2016. The current cost estimate includes costs through March 31, 2016. As a result of the additional factors that have the potential to impact start-up and operational readiness activities for this first-of-a-kind technology as described herein, the risk of further schedule extensions and/or cost increases, which could be material, remains. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information, including the discussion of risks related to the Kemper IGCC.
On February 12, 2015, the Mississippi Supreme Court (Court) issued its decision in a legal challenge filed by Thomas A. Blanton with respect to the Mississippi PSC's March 2013 order that authorized the collection of \$156 million annually (2013 MPSC Rate Order) to be recorded as Mirror CWIP. The Court reversed the 2013 MPSC Rate Order, deemed the 2013 Settlement Agreement (defined below) between the Company and the Mississippi PSC unenforceable due to a lack of public notice for the related proceedings, and directed the Mississippi PSC to enter an order requiring the Company to refund the Mirror CWIP amounts collected pursuant to the 2013 MPSC Rate Order. As of December 31, 2014, \$257.2 million had been collected by the Company. The Company continues to analyze the Court's opinion and expects to file a motion for rehearing. See "2015 Mississippi Supreme Court Decision" herein for

additional information.

Key Performance Indicators

The Company continues to focus on several key performance indicators, including the construction and start-up of the Kemper IGCC, to measure the Company's performance for customers and employees.

In recognition that the Company's long-term financial success is dependent upon how well it satisfies its customers' needs, the Company's retail base rate mechanism, PEP, includes performance indicators that directly tie customer service indicators to the

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Mississippi Power Company 2014 Annual Report

Company's allowed return. PEP measures the Company's performance on a 10-point scale as a weighted average of results in three areas: average customer price, as compared to prices of other regional utilities (weighted at 40%); service reliability, measured in percentage of time customers had electric service (40%); and customer satisfaction, measured in a survey of residential customers (20%). See Note 3 to the financial statements under "Retail Regulatory Matters – Performance Evaluation Plan" for more information on PEP.

In addition to the PEP performance indicators, the Company focuses on other performance measures, including broader measures of customer satisfaction, plant availability, system reliability, and net income after dividends on preferred stock. The Company's financial success is directly tied to customer satisfaction. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys to evaluate the Company's results and generally targets the top quartile in measuring performance, which the Company achieved during 2014.

Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of fossil 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 Company's 2014 fossil Peak Season EFOR of 0.55% was better than the target. Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on historical performance. The Company's 2014 performance was better than the target for these transmission and distribution reliability measures.

The Company uses net income (loss) after dividends on preferred stock as the primary measure of the Company's financial performance. The Company's results were below target for 2014 due to the increased cost estimate for the Kemper IGCC above the $2.88 billion cost cap and the 2015 Court decision. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Performance Evaluation Plan" and FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle" herein for additional information. See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance.

Earnings

The Company's net income (loss) after dividends on preferred stock was ($328.7) million in 2014 compared to ($476.6) million in 2013. The decreased net loss in 2014 was primarily the result of lower pre-tax charges of $868.0 million ($536.0 million after tax) in 2014 compared to pre-tax charges of $1.1 billion ($680.5 million after-tax) in 2013 for revisions of estimated costs expected to be incurred on the Company'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. The change was also due to wholesale base rate increases, effective in April 2013 and May 2014, and an increase in AFUDC equity primarily related to the construction of the Kemper IGCC. These changes were partially offset by a decrease in retail revenues primarily as a result of the 2015 Court decision which required the reversal of revenues recorded in 2013, increases in non-fuel operations and maintenance expenses and interest expense. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information regarding the Kemper IGCC.

The Company's net income (loss) after dividends on preferred stock was ($476.6) million in 2013 compared to $99.9 million in 2012. The decrease in 2013 was primarily the result of pre-tax charges of $1.1 billion ($680.5 million after-tax) for revisions of estimated costs expected to be incurred on the Company'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. These charges were partially offset by an increase in AFUDC equity primarily related to the construction of the Kemper IGCC which began in 2010 and an increase in revenues primarily due to retail and wholesale base rate increases and a retail rate increase related to the Kemper IGCC cost recovery that became effective in April 2013. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information regarding the Kemper IGCC.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Mississippi Power Company 2014 Annual Report

RESULTS OF OPERATIONS
A condensed statement of operations follows:

	Amount	Increase (Decrease) from Prior Year	
	2014	2014	2013
	(in millions)		
Operating revenues	$1,242.6	$97.5	$109.2
Fuel	574.0	82.7	80.0
Purchased power	42.9	(5.4)	(6.8)
Other operations and maintenance	270.7	17.3	24.7
Depreciation and amortization	97.1	5.7	4.9
Taxes other than income taxes	79.1	(1.5)	1.2
Estimated loss on Kemper IGCC	868.0	(234.0)	1,024.0
Total operating expenses	1,931.8	(135.2)	1,128.0
Operating income	(689.2)	232.7	(1,018.8)
Allowance for equity funds used during construction	136.4	14.8	56.8
Interest expense, net of amounts capitalized	(45.3)	(8.8)	(4.4)
Other income (expense), net	(14.1)	(8.1)	(7.3)
Income taxes (benefit)	(285.2)	82.6	(388.4)
Net income (loss)	(327.0)	148.0	(576.5)
Dividends on preferred stock	1.7	—	—
Net income (loss) after dividends on preferred stock	$(328.7)	$148.0	$(576.5)

Operating Revenues
Operating revenues for 2014 were $1.2 billion, reflecting a $97.5 million increase from 2013. Details of operating revenues were as follows:

	Amount	
	2014	2013
	(in millions)	
Retail — prior year	$799.1	$747.5
Estimated change resulting from —		
Rates and pricing	(11.5)	18.2
Sales growth (decline)	(1.5)	(0.7)
Weather	2.9	1.2
Fuel and other cost recovery	5.6	32.9
Retail — current year	794.6	799.1
Wholesale revenues —		
Non-affiliates	322.7	293.9
Affiliates	107.2	34.8
Total wholesale revenues	429.9	328.7
Other operating revenues	18.1	17.4
Total operating revenues	$1,242.6	$1,145.2
Percent change	8.5%	10.5%

Total retail revenues for 2014 decreased $4.5 million, or 0.6%, compared to 2013 primarily as a result of $10.3 million in revenues recorded in 2013 that were reversed in 2014 as a result of the 2015 Court decision. See Note 3 to the financial

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Mississippi Power Company 2014 Annual Report

statements under "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs – 2015 Mississippi Supreme Court Decision" for additional information. This decrease was partially offset by a PEP base rate increase, effective in March 2013, of $2.8 million and a $4.7 million refund in 2013 related to the annual PEP lookback filing. See Note 3 to the financial statements under "Retail Regulatory Matters – Performance Evaluation Plan" for additional information. Total retail revenues for 2013 increased $51.6 million, or 6.9%, compared to 2012 primarily as a result of a base rate increase, a rate increase related to Kemper IGCC cost recovery that became effective in April 2013, and higher fuel cost recovery revenues in 2013 compared to 2012.

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

Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, including the energy component of purchased power costs. Under these provisions, fuel revenues generally equal fuel expenses, including the energy component of purchased power costs, and do not affect net income. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Fuel Cost Recovery" herein for additional information. Fuel and other cost recovery revenues increased in 2014 and 2013 compared to prior years primarily as a result of higher recoverable fuel costs.

Recoverable fuel costs include fuel and purchased power expenses reduced by the fuel and emissions portion of wholesale revenues from energy sold to customers outside the Company's service territory.

Wholesale revenues from power sales to non-affiliated utilities, including FERC-regulated MRA sales as well as market-based sales, were as follows:

	2014	2013	2012
	(in millions)		
Capacity and other	$160.3	$143.0	$122.5
Energy	162.4	150.9	133.1
Total non-affiliated	$322.7	$293.9	$255.6

Wholesale revenues from sales to non-affiliates will vary depending on fuel prices, the market prices of wholesale energy compared to the cost of the Company's and the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation. Increases and decreases in 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. The Company serves long-term contracts with rural electric cooperative associations and municipalities located in southeastern Mississippi under cost-based electric tariffs which are subject to regulation by the FERC. The contracts with these wholesale customers represented 21.9% of the Company’s total operating revenues in 2014 and are largely subject to rolling 10-year cancellation notices.

Wholesale revenues from sales to non-affiliates increased $28.8 million, or 9.8%, in 2014 compared to 2013 as a result of a $17.3 million increase in base revenues primarily resulting from wholesale base rate increases effective April 1, 2013 and May 1, 2014 and an $11.5 million increase in energy revenues, of which $10.0 million was associated with an increase in KWH sales and $1.5 million was associated with higher fuel prices. Wholesale revenues from sales to non-affiliates increased $38.4 million, or 15.0%, in 2013 compared to 2012 as a result of a $20.5 million increase in base revenues primarily resulting from a wholesale base rate increase effective April 1, 2013 and a $17.8 million increase in energy revenues, of which $14.0 million was associated with higher fuel prices and $3.8 million was associated with an increase in KWH sales.

Short-term opportunity energy sales are also included in sales for resale to non-affiliates. These opportunity sales are made at market-based rates that generally provide a margin above the Company's variable cost to produce the energy.

Wholesale revenues from sales to affiliates will vary depending on demand and the availability and cost of generating resources at each company. These affiliate sales are made in accordance with the Intercompany Interchange Contract (IIC), as approved by the FERC. These transactions do not have a significant impact on earnings since this energy is generally sold at marginal cost.

Wholesale revenues from sales to affiliates increased $72.4 million, or 208.3%, in 2014 compared to 2013 primarily due to a $74.6 million increase in energy revenues of which $69.3 million was associated with an increase in KWH sales and $5.3 million was associated with higher prices, partially offset by a decrease in capacity revenues of $2.2 million. Wholesale revenues from sales to affiliates increased $18.4 million, or 112.0%, in 2013 compared to 2012 due to a $1.3 million increase in capacity revenues and a $17.1 million increase in energy revenues of which $7.2 million was associated with higher prices and $9.9 million was associated with an increase in KWH sales.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Mississippi Power Company 2014 Annual Report

Other operating revenues in 2014 increased $0.7 million, or 4.2%, from 2013 primarily due to a $1.3 million increase in transmission revenues, partially offset by a $0.6 million decrease in microwave tower lease revenue and a $0.2 million decrease in miscellaneous revenues from timber and easement sale proceeds. Other operating revenues in 2013 increased $0.8 million, or 4.8%, from 2012 primarily due to a $0.5 million increase in transmission revenues and a $0.3 million increase in miscellaneous revenue from timber and easement sale proceeds.

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2014 and the percent change from the prior year were as follows:

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2014	2014	2013	2014	2013
	(in millions)				
Residential	2,126	1.8 %	2.0 %	(2.3)%	— %
Commercial	2,859	(0.2)	(1.7)	0.1	(1.1)
Industrial	4,943	4.3	0.8	4.3	0.8
Other	41	1.1	4.0	1.1	4.0
Total retail	9,969	2.4	0.3 %	1.6 %	0.1 %
Wholesale					
Non-affiliated	4,191	6.7	2.9		
Affiliated	2,900	211.4	62.8		
Total wholesale	7,091	45.9	10.7		
Total energy sales	17,060	16.9 %	3.5 %		

Changes in retail energy sales are generally the result of changes in electricity usage by customers, changes in weather, and changes in the number of customers.

Residential energy sales increased 1.8% in 2014 compared to 2013 due to colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013. Weather-adjusted residential energy sales decreased 2.3% in 2014 compared to 2013 due to lower average usage per customer. Household income, one of the primary drivers of residential customer usage, was flat in 2014. Residential energy sales increased 2.0% in 2013 compared to 2012 due to less mild weather and a slight increase in the number of residential customers in 2013 compared to 2012.

Commercial energy sales decreased 1.7% in 2013 compared to 2012 due to decreased economic activity in 2013 compared to 2012.

Industrial energy sales increased 4.3% in 2014 compared to 2013 due to increased production related to expanded operation by many industrial customers. Industrial energy sales increased 0.8% in 2013 compared to 2012 due to increased usage by larger industrial customers as well as expansions by existing customers.

Wholesale energy sales to non-affiliates increased 6.7% in 2014 compared to 2013 primarily due to increased opportunity sales to the external market as a result of lower system prices. Wholesale energy sales to non-affiliates increased 2.9% in 2013 compared to 2012 primarily due to increased KWH sales to rural electric cooperative associations and municipalities located in southeastern Mississippi resulting from less mild weather in 2013 compared to 2012.

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

Wholesale energy sales to affiliates increased 211.4% in 2014 compared to 2013 primarily due to an increase in the Company's generation, resulting in more energy available to sell to affiliate companies. Wholesale energy sales to affiliates increased 62.8% in 2013 compared to 2012 primarily due to an increase in the Company's generation, resulting in more energy available to sell to affiliate companies.

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Fuel and Purchased Power Expenses
Fuel costs constitute the single largest expense for the Company. The mix of fuel sources for generation of electricity is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units. Additionally, the Company purchases a portion of its electricity needs from the wholesale market.
Details of the Company's generation and purchased power were as follows:

	2014	2013	2012
Total generation (millions of KWHs)	16,881	13,721	12,750
Total purchased power (millions of KWHs)	886	1,559	1,961
Sources of generation (percent) –			
Coal	42	36	26
Gas	58	64	74
Cost of fuel, generated (cents per net KWH) –			
Coal	3.96	4.97	5.09
Gas	3.37	3.16	2.90
Average cost of fuel, generated (cents per net KWH)	3.64	3.87	3.53
Average cost of purchased power (cents per net KWH)	4.85	3.10	2.81

Fuel and purchased power expenses were $616.9 million in 2014, an increase of $77.3 million, or 14.3%, above the prior year costs. The increase was primarily due to a $114.4 million increase in the total volume of KWHs generated, offset by a $37.1 million decrease in the cost of fuel and purchased power. Fuel and purchased power expenses were $539.6 million in 2013, an increase of $73.2 million, or 15.7%, above the prior year costs. The increase was primarily due to a $55.1 million increase in the total volume of KWHs generated and purchased and an $18.1 million increase in the cost of fuel and purchased power.
Fuel and purchased power energy transactions do not have a significant impact on earnings, since energy expenses are generally offset by energy revenues through the Company's fuel cost recovery clauses. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Fuel Cost Recovery" and Note 1 to the financial statements under "Fuel Costs" for additional information.
Fuel
Fuel expense increased $82.7 million, or 16.8%, in 2014 compared to 2013. The increase was the result of a 24.5% increase in the volume of KWHs generated in 2014, partially offset by a 5.9% decrease in the average cost of fuel per KWH generated. Fuel expense increased $80.0 million, or 19.5%, in 2013 compared to 2012. The increase was the result of a 9.6% increase in the average cost of fuel per KWH generated and a 9.0% increase in the volume of KWHs generated resulting from increased non-territorial sales in 2013 compared to 2012.
Purchased Power - Non-Affiliates
Purchased power expense from non-affiliates increased $12.1 million, or 210.3%, in 2014 compared to 2013. The increase was primarily the result of a 276.7% increase in the average cost per KWH purchased, partially offset by a 17.6% decrease in the volume of KWHs purchased. Purchased power expense from non-affiliates increased $0.5 million, or 10.2%, in 2013 compared to 2012. The increase was the result of an 8.0% increase in the average cost per KWH purchased and a 2.0% increase in the volume of KWHs purchased. The increase in the average cost per KWH purchased was due to a higher marginal cost of fuel. The increase in the volume of KWHs purchased was due to a lower market cost of available energy compared to the cost of generation.
Energy purchases from non-affiliates will vary depending on the market prices of wholesale energy compared to the cost of the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation.
Purchased Power - Affiliates
Purchased power expense from affiliates decreased $17.5 million, or 41.1%, in 2014 compared to 2013. The decrease in 2014 was primarily the result of a 49.5% decrease in the volume of KWHs purchased, offset by a 16.8% increase in

the average cost per KWH purchased compared to 2013. Purchased power expense from affiliates decreased $7.3 million, or 14.7%, in 2013 compared to 2012. The decrease was primarily the result of a 24.7% decrease in the volume of KWHs purchased, partially offset by a 13.2% increase in the average cost per KWH purchased compared to 2012.

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Energy purchases from affiliates will vary depending on demand for energy and the availability and cost of generating resources at each company within the Southern Company system. These purchases are made in accordance with the IIC or other contractual agreements, as approved by the FERC.

Other Operations and Maintenance Expenses

Other operations and maintenance expenses increased $17.3 million, or 6.8%, in 2014 compared to 2013 primarily due to a $14.1 million increase in employee compensation and benefit expenses and a $6.5 million increase in generation maintenance expenses. These increases in 2014 were partially offset by a $2.0 million decrease in transmission expenses primarily related to overhead line maintenance and vegetation management, and a $0.8 million decrease in customer accounting expenses primarily due to uncollectibles.

Other operations and maintenance expenses increased $24.7 million, or 10.8%, in 2013 compared to 2012 primarily due to a $9.8 million increase in generation maintenance expenses for several planned outages, a $7.6 million increase in administrative and general expenses related to pension expense, a $4.2 million increase in transmission maintenance expenses, a $2.8 million increase in customer accounting primarily due to uncollectibles, and a $2.5 million increase in distribution expenses related to overhead line maintenance and vegetation management. These increases were partially offset by a $2.7 million decrease in labor expenses.

Depreciation and Amortization

Depreciation and amortization increased $5.7 million, or 6.3%, in 2014 compared to 2013 primarily due to a $4.2 million increase related to the reversal of a regulatory deferral associated with the Kemper IGCC municipal franchise taxes, a $2.2 million increase in depreciation related to an increase in assets in service, and a $2.2 million increase resulting from a regulatory deferral associated with the purchase of Plant Daniel Units 3 and 4. These increases were partially offset by a $3.7 million decrease associated with a wholesale revenue requirement adjustment.

Depreciation and amortization increased $4.9 million, or 5.7%, in 2013 compared to 2012 primarily due to a $4.3 million increase in ECO Plan amortization, a $2.0 million increase in amortization resulting from a regulatory deferral associated with the purchase of Plant Daniel Units 3 and 4, and a $1.6 million increase in depreciation resulting from an increase in plant in service. These increases were partially offset by a $2.1 million decrease in amortization primarily resulting from a regulatory deferral associated with the Kemper IGCC and a $0.7 million decrease in amortization resulting from a regulatory deferral associated with the capital lease related to the Kemper IGCC air separation unit.

See Note 1 to the financial statements under "Depreciation and Amortization" and Note 3 to the financial statements under "FERC Matters," "Retail Regulatory Matters – Performance Evaluation Plan," and " – Environmental Compliance Overview Plan" for additional information.

Taxes Other Than Income Taxes

Taxes other than income taxes decreased $1.5 million, or 2.0%, in 2014 compared to 2013 primarily as a result of a $6.0 million decrease in franchise taxes, partially offset by a $3.2 million increase in ad valorem taxes and a $1.3 million increase in payroll taxes. Taxes other than income taxes increased $1.2 million, or 1.6%, in 2013 compared to 2012 primarily as a result of a $3.5 million increase in franchise taxes, partially offset by a $2.1 million decrease in ad valorem taxes and a $0.2 million decrease in payroll taxes.

The retail portion of ad valorem taxes is recoverable under the Company's ad valorem tax cost recovery clause and, therefore, does not affect net income.

Estimated Loss on Kemper IGCC

Estimated probable losses on the Kemper IGCC of $868.0 million and $1.1 billion were recorded in 2014 and 2013, respectively, to reflect revisions of estimated costs expected to be incurred on the 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 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 $14.8 million, or 12.2%, in 2014 as compared to 2013 and $56.8 million, or 87.7%, in 2013 as compared to 2012. These increases in 2014 and 2013 were primarily due to CWIP related to the Company's Kemper IGCC. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Allowance for Funds Used During

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

Interest Expense, Net of Amounts Capitalized

Interest expense, net of amounts capitalized increased $8.8 million, or 24.2%, in 2014 compared to 2013, primarily due to an $11.0 million increase in interest expense resulting from the receipt of $75.0 million and $50.0 million interest-bearing refundable deposits from SMEPA in January 2014 and October 2014, respectively, related to its pending purchase of an undivided interest in the Kemper IGCC, an $8.2 million increase in interest expense on the regulatory liability related to the Kemper IGCC rate recovery, a $4.6 million increase in interest expense primarily associated with the issuances of long-term debt in 2014, and a $2.8 million increase in other interest expense. These increases in 2014 over the prior year were partially offset by a $14.6 million increase in capitalized interest resulting from carrying costs associated with the Kemper IGCC and a $3.2 million decrease in interest expense primarily associated with the redemption of long-term debt in late 2013.

Interest expense, net of amounts capitalized decreased $4.4 million, or 10.7%, in 2013 compared to 2012, primarily due to a $20.1 million increase in capitalized interest resulting from AFUDC debt associated with the Kemper IGCC and a $2.6 million decrease in interest expense associated with the redemption of long-term debt in 2013. These decreases in 2013 from the prior year were partially offset by a $12.2 million increase in interest expense primarily associated with the issuances of new long-term debt in 2013, a $4.0 million increase in interest expense resulting from the receipt of a $150.0 million interest-bearing refundable deposit from SMEPA in March 2012 related to its pending purchase of an undivided interest in the Kemper IGCC, and a $2.7 million increase in interest expense in the regulatory liability related to the Kemper IGCC rate recovery.

See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle – Proposed Sale of Undivided Interest to SMEPA" for more information.

Other Income (Expense), Net

Other income (expense), net decreased $8.1 million, or 133.7%, in 2014 compared to 2013 primarily due to $7.0 million associated with the Sierra Club settlement and a $1.1 million increase in consulting fees. Other income (expense), net decreased $7.3 million in 2013 compared to 2012 primarily due to a $5.9 million increase in consulting fees. See "Other Matters – Sierra Club Settlement Agreement" herein and Note 3 to the financial statements under "Other Matters – Sierra Club Settlement Agreement" for additional information.

Income Taxes (Benefit)

Income taxes (benefit) increased $82.6 million, or 22.5%, in 2014 compared to 2013 and decreased $388.4 million in 2013 compared to 2012 primarily resulting from the reduction in pre-tax losses related to the estimated probable losses on the Kemper IGCC.

Effects of Inflation

The Company is subject to rate regulation that is generally based on the recovery of historical and projected costs. The effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. Any adverse effect of inflation on the Company's results of operations has not been substantial in recent years.

FUTURE EARNINGS POTENTIAL

General

The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located in southeast Mississippi and to wholesale customers in the Southeast. Prices for electricity provided by the Company to retail customers are set by the Mississippi PSC under cost-based regulatory principles. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. Prices for wholesale electricity sales, interconnecting transmission lines, and the exchange of electric power are regulated by the FERC. See "FERC Matters" herein, ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Electric Utility Regulation" herein, and Note 3 to the financial statements under "Retail Regulatory

Matters" for additional information about regulatory matters.
The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the Company's ability to prevail against legal challenges associated with the Kemper IGCC, recover its prudently-incurred costs in a timely manner during a time of increasing costs and the completion and subsequent operation of the Kemper IGCC and the Plant Daniel scrubber project as well as other ongoing construction projects.

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Future earnings in the near term will depend, in part, upon maintaining and growing sales which are subject to a number of factors. These factors include weather, competition, new energy contracts with other utilities, energy conservation practiced by customers, the use of alternative energy sources by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in the Company's service territory. Changes in regional and global economic conditions may impact sales for the Company, as the pace of the economic recovery remains uncertain. The timing and extent of the economic recovery will impact growth and may impact future earnings.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis or through market-based contracts. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified. 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 EPA brought civil enforcement actions in federal district court against Alabama Power alleging violations of the New Source Review provisions of the Clean Air Act at certain coal-fired electric generating units, including a unit co-owned by the Company. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. See Note 3 to the financial statements under "Environmental Matters – New Source Review Actions" for additional information. The ultimate outcome of these matters cannot be determined at this time.

Environmental Statutes and Regulations

General

The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; the Endangered Species Act; and related federal and state regulations. Compliance with these environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. Through 2014, the Company had invested approximately $523 million in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $118 million, $104 million, and $52 million for 2014, 2013, and 2012, respectively. The Company expects that capital expenditures to comply with environmental statutes and regulations will total approximately $154 million from 2015 through 2017, with annual totals of approximately $94 million, $25 million, and $35 million for 2015, 2016, and 2017, respectively. These estimated expenditures do not include any potential compliance costs that may arise from the EPA's proposed rules that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. See "Global Climate Issues" for additional information.

The Company's ultimate environmental compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital expenditures will be affected by the final requirements of new or revised environmental regulations and regulations relating to global climate change that are promulgated, including the proposed environmental regulations described below; the outcome of any legal challenges to the environmental rules; the cost, availability, and existing inventory of emissions allowances; and the Company's fuel mix. Compliance costs may arise from existing unit retirements, installation of additional environmental controls, closure and monitoring of

CCR facilities, and adding or changing fuel sources for certain existing units. The ultimate outcome of these matters cannot be determined at this time. See Note 3 to the financial statements under "Other Matters – Sierra Club Settlement Agreement" for additional information.

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

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Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Company. Since 1990, the Company has spent approximately $393 million in reducing and monitoring emissions pursuant to the Clean Air Act. Additional controls are currently planned or under consideration to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements.

In 2012, the EPA finalized the Mercury and Air Toxics Standards (MATS) rule, which imposes stringent emissions limits for acid gases, mercury, and particulate matter on coal- and oil-fired electric utility steam generating units. Compliance for existing sources is required by April 16, 2015 up to April 16, 2016 for affected units for which extensions have been granted. On November 25, 2014, the U.S. Supreme Court granted a petition for review of the final MATS rule.

The EPA regulates ground level ozone concentrations through implementation of an eight-hour ozone National Ambient Air Quality Standard (NAAQS). On December 17, 2014, the EPA published a proposed rule to further reduce the current eight-hour ozone standard. The EPA is required by federal court order to complete this rulemaking by October 1, 2015. Finalization of a lower eight-hour ozone standard could result in the designation of new ozone nonattainment areas within the Company's service territory.

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

On February 13, 2014, the EPA proposed to delete from the Alabama State Implementation Plan (SIP) the Alabama opacity rule that the EPA approved in 2008, which provides operational flexibility to affected units, including units co-owned by the Company. In March 2013, the U.S. Court of Appeals for the Eleventh Circuit ruled in favor of Alabama Power and the Company and vacated an earlier attempt by the EPA to rescind its 2008 approval. The EPA's latest proposal characterizes the proposed deletion as an error correction within the meaning of the Clean Air Act. Alabama Power and the Company believe this interpretation of the Clean Air Act to be incorrect. If finalized, this proposed action could affect unit availability and result in increased operations and maintenance costs for affected units, including units co-owned by the Company.

The Company's service territory is subject to the requirements of the Cross State Air Pollution Rule (CSAPR). CSAPR is an emissions trading program that limits SO_2 and nitrogen oxide emissions from power plants in 28 states in two phases, with Phase I beginning in 2015 and Phase II beginning in 2017. In 2012, the U.S. Court of Appeals for the District of Columbia Circuit vacated CSAPR in its entirety, but on April 29, 2014, the U.S. Supreme Court overturned that decision and remanded the case back to the U.S. Court of Appeals for the District of Columbia Circuit for further proceedings. The U.S. Court of Appeals for the District of Columbia Circuit granted the EPA's motion to lift the stay of the rule, and the first phase of CSAPR took effect on January 1, 2015.

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, including fossil fuel-fired generating facilities, built between 1962 and 1977 and any additional emissions reductions necessary for each designated area to achieve reasonable progress toward the natural visibility conditions goal by 2018 and for each 10-year period thereafter.

In 2012, the EPA published proposed revisions to the New Source Performance Standard (NSPS) for Stationary Combustion Turbines (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.

In February 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 proposed to supplement the 2013 proposed rule on September 17, 2014, making it more stringent. The EPA has entered into a settlement agreement requiring it to finalize the proposed rule by May 22, 2015. The proposed rule would require states subject to the rule (including Alabama and Mississippi) to revise their SSM provisions within 18 months after issuance of the final rule.

The Company has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the current and proposed environmental requirements discussed above. The impacts of the eight-hour ozone and SO_2 NAAQS, the Alabama opacity rule, CSAPR, CAVR, the MATS rule, the NSPS for CTs, and the SSM rule on the

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Company cannot be determined at this time and will depend on the specific provisions of the proposed and final rules, the resolution of pending and future legal challenges, and/or the development and implementation of rules at the state level. These regulations could result in significant additional 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.

See Note 3 to the financial statements under "Retail Regulatory Matters – Environmental Compliance Overview Plan" and "Other Matters – Sierra Club Settlement Agreement" for additional information.

Water Quality

The EPA's final rule establishing standards for reducing effects on fish and other aquatic life caused by new and existing cooling water intake structures at existing power plants and manufacturing facilities became effective on October 14, 2014. The effect of this final rule will depend on the results of additional studies and implementation of the rule by regulators based on site-specific factors. The ultimate impact of this rule will also depend on the outcome of ongoing legal challenges and cannot be determined at this time.

In June 2013, the EPA published a proposed rule which requested comments on a range of potential regulatory options for addressing revised technology-based limits for certain wastestreams from steam electric power plants and best management practices for CCR surface impoundments. The EPA has entered into a consent decree requiring it to finalize revisions to the steam electric effluent guidelines by September 30, 2015. The ultimate impact of the rule will also depend on the specific technology requirements of the final rule and the outcome of any legal challenges and cannot be determined at this time.

On April 21, 2014, the EPA and the U.S. Army Corps of Engineers jointly published a proposed rule to revise the regulatory definition of waters of the U.S. for all Clean Water Act (CWA) programs, which would significantly expand the scope of federal jurisdiction under the CWA. In addition, the rule as proposed could have significant impacts on economic development projects which could affect customer demand growth. The ultimate impact of the proposed rule will depend on the specific requirements of the final rule and the outcome of any legal challenges and cannot be determined at this time. If finalized as proposed, this rule could significantly increase permitting and regulatory requirements and costs associated with the siting of new facilities and the installation, expansion, and maintenance of transmission and distribution lines.

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

Coal Combustion Residuals

The Company currently manages two electric generating plants in Mississippi and is also part owner of a plant located in Alabama, each with onsite CCR storage units consisting of landfills and surface impoundments (CCR Units). In addition to on-site storage, the Company also sells a portion of its CCR to third parties for beneficial reuse. Individual states regulate CCR and the States of Mississippi and Alabama each have their own regulatory requirements. The Company has an inspection program in place to assist in maintaining the integrity of its coal ash surface impoundments.

On December 19, 2014, the EPA issued the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule), but has not yet published it in the Federal Register. The CCR Rule will regulate the disposal of CCR, including coal ash and gypsum, as non-hazardous solid waste in CCR Units at active generating power plants. The CCR Rule does not mandate closure of CCR Units, but includes minimum criteria for active and inactive surface impoundments containing CCR and liquids, lateral expansions of existing units, and active landfills. Failure to meet the minimum criteria can result in the mandated closure of a CCR Unit. Although the EPA does not require individual states to adopt the final criteria, states have the option to incorporate the federal criteria into their state solid waste management plans in order to regulate CCR in a manner consistent with federal standards. The EPA's final rule continues to exclude the beneficial use of CCR from regulation.

The ultimate impact of the CCR Rule cannot be determined at this time and will depend on the Company's ongoing review of the CCR Rule, the results of initial and ongoing minimum criteria assessments, and the outcome of legal challenges. The cost and timing of potential ash pond closure and ongoing monitoring activities that may be required in connection with the CCR Rule is also uncertain; however, the Company has developed a preliminary nominal dollar estimate of costs associated with closure and groundwater monitoring of ash ponds in place of approximately $64 million and ongoing post-closure care of approximately $12 million. The Company will record asset retirement obligations (ARO) for the estimated closure costs required under the CCR Rule during 2015. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates.

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Environmental Remediation
The Company must comply with other environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company could incur substantial costs to clean up properties. The Company conducts studies to determine the extent of any required cleanup and has recognized in its financial statements the costs to clean up known impacted sites. Amounts for cleanup and ongoing monitoring costs were not material for any year presented. The Company has authority from the Mississippi PSC to recover approved environmental compliance costs through its ECO clause. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Note 3 to the financial statements under "Environmental Matters – Environmental Remediation" for additional information.
Global Climate Issues
In 2014, the EPA published three sets of proposed standards that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. On January 8, 2014, the EPA published proposed standards for new units, and, on June 18, 2014, the EPA published proposed standards governing existing units, known as the Clean Power Plan, and separate standards governing CO_2 emissions from modified and reconstructed units. The EPA's proposed Clean Power Plan establishes guidelines for states to develop plans to address CO_2 emissions from existing fossil fuel-fired electric generating units. The EPA's proposed guidelines establish state-specific interim and final CO_2 emission rate goals to be achieved between 2020 and 2029 and in 2030 and thereafter. The proposed guidelines and standards could result in operational restrictions and material compliance costs, including capital expenditures, which could affect future unit retirement and replacement decisions. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates or through market-based contracts.
The Southern Company system filed comments on the EPA's proposed Clean Power Plan on December 1, 2014. These comments addressed legal and technical issues in addition to providing a preliminary estimated cost of complying with the proposed guidelines utilizing one of the EPA's compliance scenarios. Costs associated with this proposal could be significant to the utility industry and the Southern Company system. However, the ultimate financial and operational impact of the proposed Clean Power Plan on the Southern Company system cannot be determined at this time and will depend upon numerous known and unknown factors. Some of the unknown factors include: the structure, timing, and content of the EPA's final guidelines; individual state implementation of these guidelines, including the potential that state plans impose different standards; additional rulemaking activities in response to legal challenges and related court decisions; the impact of future changes in generation and emissions-related technology and costs; the impact of future decisions regarding unit retirement and replacement, including the type and amount of any such replacement capacity; and the time periods over which compliance will be required.
Over the past several years, the U.S. Congress has also 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.
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 Company's 2013 greenhouse gas emissions were approximately 10 million metric tons of CO_2 equivalent. The preliminary estimate of the Company's 2014 greenhouse gas emissions on the same basis is approximately 11 million metric tons of CO_2 equivalent. The level of greenhouse gas emissions from year to year will depend on the level of generation, the mix of fuel sources, and other factors.
FERC Matters
In May 2013, the FERC accepted a settlement agreement entered into by the Company with its wholesale customers which approved, among other things, the same regulatory treatment for tariff ratemaking as the treatment approved for retail ratemaking by the Mississippi PSC for certain items. The regulatory treatment includes (i) approval to establish

a regulatory asset for the portion of non-capitalizable Kemper IGCC-related costs which have been and will continue to be incurred during the construction period for the Kemper IGCC, (ii) authorization to defer as a regulatory asset, for the 10-year period ending October 2021, the difference between the revenue requirement under the purchase option of Plant Daniel Units 3 and 4 (assuming a remaining 30-year life) and the revenue requirement assuming the continuation of the operating lease regulatory treatment with the accumulated deferred balance at the end of the deferral being amortized into wholesale rates over the remaining life of Plant Daniel Units 3 and 4, and (iii) authority to defer in a regulatory asset costs related to the retirement or partial retirement of generating units as a result of environmental compliance rules. See Note 3 to the financial statements under "FERC Matters" for more information.

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On March 31, 2014, the Company reached a settlement agreement with its wholesale customers and filed a request with the FERC for an increase in the MRA cost-based electric tariff. The settlement agreement, accepted by the FERC on May 20, 2014, provides that base rates under the MRA cost-based electric tariff will increase approximately $10.1 million annually, with revised rates effective for services rendered beginning May 1, 2014.

Retail Regulatory Matters

General

The Company's rates and charges for service to retail customers are subject to the regulatory oversight of the Mississippi PSC. The Company's rates are a combination of base rates and several separate cost recovery clauses for specific categories of costs. These separate cost recovery clauses address such items as the Kemper IGCC, fuel and purchased power, energy efficiency programs, ad valorem taxes, property damage, and the costs of compliance with environmental laws and regulations. Costs not addressed through one of the specific cost recovery clauses are recovered through the Company's base rates. See Note 3 to the financial statements under "Retail Regulatory Matters" and "Integrated Coal Gasification Combined Cycle" for additional information.

In 2012, the Mississippi PSC issued an order for the purpose of investigating and reviewing, for informational purposes only, the ROE formulas used by the Company and all other regulated electric utilities in Mississippi. In March 2013, the MPUS filed with the Mississippi PSC its report on the ROE formulas used by the Company and all other regulated electric utilities in Mississippi. The ultimate outcome of this matter cannot be determined at this time.

Energy Efficiency

In July 2013, the Mississippi PSC approved an energy efficiency and conservation rule requiring electric and gas utilities in Mississippi serving more than 25,000 customers to implement energy efficiency programs and standards. On June 3, 2014, the Mississippi PSC approved the Company's 2014 Energy Efficiency Quick Start Plan filing, which includes a portfolio of energy efficiency programs. On October 20, 2014, the Company filed a revised compliance filing, which proposed an increase of $6.7 million in retail revenues for the period December 2014 through December 2015. The Mississippi PSC approved the revised filing on November 4, 2014.

Performance Evaluation Plan

The Company’s retail base rates are set under the PEP, a rate plan approved by the Mississippi PSC. Two filings are made for each calendar year: the PEP projected filing, which is typically filed prior to the beginning of the year based on projected revenue requirement, and the PEP lookback filing, which is filed after the year and allows for review of the actual revenue requirement compared to the projected filing.

In 2011, the Company submitted its annual PEP lookback filing for 2010, which recommended no surcharge or refund. Later in 2011, the Company received a letter from the MPUS disputing certain items in the 2010 PEP lookback filing. In 2012, the Mississippi PSC issued an order canceling the Company's PEP lookback filing for 2011. In May 2013, the MPUS contested the Company's PEP lookback filing for 2012, which indicated a refund due to customers of $4.7 million. Unresolved matters related to certain costs included in the 2010 PEP lookback filing, which are currently under review, also impact the 2012 PEP lookback filing.

In March 2013, the Mississippi PSC approved the projected PEP filing for 2013, which resulted in a rate increase of 1.9%, or $15.3 million, annually, effective March 19, 2013. The Company may be entitled to $3.3 million in additional revenues related to 2013 as a result of the late implementation of the 2013 PEP rate increase.

On March 18, 2014, the Company submitted its annual PEP lookback filing for 2013, which indicated no surcharge or refund. On March 31, 2014, the Mississippi PSC suspended the filing to allow more time for review.

On June 3, 2014, the Mississippi PSC issued an order for the purpose of investigating and reviewing the adoption of a uniform formula rate plan for the Company and other regulated electric utilities in Mississippi.

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

Environmental Compliance Overview Plan

In 2012, the Mississippi PSC approved the Company's request for a CPCN to construct scrubbers on Plant Daniel Units 1 and 2, which are scheduled to be placed in service in September and November 2015, respectively. These units are jointly owned by the Company and Gulf Power, with 50% ownership each. On August 1, 2014, the Company entered into a settlement agreement with

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the Sierra Club (Sierra Club Settlement Agreement) that, among other things, requires the Sierra Club to dismiss or withdraw all pending legal and regulatory challenges to the issuance of the CPCN to construct scrubbers on Plant Daniel Units 1 and 2. In addition, and consistent with the Company's ongoing evaluation of recent environmental rules and regulations, the Company agreed to retire, repower with natural gas, or convert to an alternative non-fossil fuel source Plant Sweatt Units 1 and 2 (80 MWs) no later than December 2018. The Company also agreed that it would cease burning coal and other solid fuel at Plant Watson Units 4 and 5 (750 MWs) and begin operating those units solely on natural gas no later than April 2015, and cease burning coal and other solid fuel at Plant Greene County Units 1 and 2 (200 MWs) and begin operating those units solely on natural gas no later than April 2016. On August 28, 2014, the Chancery Court of Harrison County, Mississippi dismissed the Sierra Club's appeal related to the CPCN to construct scrubbers on Plant Daniel Units 1 and 2.

In accordance with a 2011 accounting order from the Mississippi PSC, the Company has the authority to defer in a regulatory asset for future recovery all plant retirement- or partial retirement-related costs resulting from environmental regulations. This request was made to minimize the potential rate impact to customers arising from pending and final environmental regulations which may require the premature retirement of some generating units. As of December 31, 2014, $5.6 million of Plant Greene County costs and $2.0 million of costs related to Plant Watson have been reclassified as a regulatory asset. These costs are expected to be recovered through the ECO plan and other existing cost recovery mechanisms. Additional costs associated with the remaining net book value of coal-related equipment will be reclassified to a regulatory asset at the time of retirement for Plants Watson and Greene County in 2015 and 2016, respectively. Approved regulatory asset costs will be amortized over a period to be determined by the Mississippi PSC. As a result, these decisions are not expected to have a material impact on the Company's financial statements.

See Note 3 to the financial statements under "Other Matters – Sierra Club Settlement Agreement" for additional information.

On February 25, 2015, the Company submitted its annual ECO filing for 2015, which indicated an annual increase in revenues of approximately $8.1 million.

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

Fuel Cost Recovery

The Company establishes, annually, a retail fuel cost recovery factor that is approved by the Mississippi PSC. The Company is required to file for an adjustment to the retail fuel cost recovery factor annually; the most recent filing occurred on November 17, 2014. On January 13, 2015, the Mississippi PSC approved the 2015 retail fuel cost recovery factor, effective January 21, 2015. The retail fuel cost recovery factor will result in an annual increase of approximately $7.9 million. At December 31, 2014, the amount of under-recovered retail fuel costs included in the balance sheets was $2.5 million compared to a $14.5 million over-recovered balance at December 31, 2013.

The Company also has a wholesale MRA and a Market Based (MB) fuel cost recovery factor. Effective January 1, 2015, the wholesale MRA fuel rate decreased resulting in an annual decrease of $1.1 million. Effective February 1, 2015, the wholesale MB fuel rate decreased, resulting in an annual decrease of $0.1 million. At December 31, 2014, the amount of over-recovered wholesale MRA fuel costs included in the balance sheets was $0.2 million compared to an over-recovered balance of $7.3 million at December 31, 2013. At December 31, 2014, the amount of over-recovered wholesale MB fuel costs included in the balance sheets was immaterial compared to an over-recovered balance of $0.3 million at December 31, 2013. In addition, at December 31, 2014, the amount of over-recovered MRA emissions allowance cost included in the balance sheets was $0.3 million compared to a $3.8 million under-recovered balance at December 31, 2013. The Company's operating revenues are adjusted for differences in actual recoverable fuel cost and amounts billed in accordance with the currently approved cost recovery rate. Accordingly, changes in the billing factor should have no significant effect on the Company's revenues or net income, but will affect cash flow.

Ad Valorem Tax Adjustment

The Company establishes, annually, an ad valorem tax adjustment factor that is approved by the Mississippi PSC to collect the ad valorem taxes paid by the Company. On May 6, 2014, the Mississippi PSC approved the Company's annual ad valorem tax adjustment factor filing for 2014, in which the Company requested an annual rate increase of 0.38%, or $3.6 million in annual retail revenues, primarily due to an increase in property tax rates.

See RESULTS OF OPERATIONS – "Taxes Other Than Income Taxes" herein for additional information.

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

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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. In the Court decision, the Court declined to rule on the constitutionality of the Baseload Act. See "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs" and " – 2015 Mississippi Supreme Court Decision" herein for additional information.

Integrated Coal Gasification Combined Cycle

Kemper IGCC Overview

Construction of the Kemper IGCC is nearing completion and start-up activities will continue until the Kemper IGCC is placed in service. The Kemper IGCC will utilize an IGCC technology with an output capacity of 582 MWs. The Kemper IGCC will be fueled by locally mined lignite (an abundant, lower heating value coal) from a mine owned by the Company and situated adjacent to the Kemper IGCC. The mine, operated by North American Coal Corporation, started commercial operation in June 2013. In connection with the Kemper IGCC, the Company constructed and plans to operate approximately 61 miles of CO_2 pipeline infrastructure for the planned transport of captured CO_2 for use in enhanced oil recovery.

Kemper IGCC Schedule and Cost Estimate

In 2012, the Mississippi PSC issued the 2012 MPSC CPCN Order, a detailed order confirming the CPCN originally approved by the Mississippi PSC in 2010 authorizing the acquisition, construction, and operation of the Kemper IGCC.

The certificated cost estimate of the Kemper IGCC included in the 2012 MPSC CPCN Order was $2.4 billion, net of $245.3 million of DOE Grants and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, and AFUDC related to the Kemper IGCC. The 2012 MPSC CPCN Order approved a construction cost cap of up to $2.88 billion, with recovery of prudently-incurred costs subject to approval by the Mississippi PSC.

The Kemper IGCC was originally projected to be placed in service in May 2014. The Company placed the combined cycle and the associated common facilities portion of the Kemper IGCC in service on natural gas on August 9, 2014 and continues to focus on completing the remainder of the Kemper IGCC, including the gasifier and the gas clean-up facilities, for which the in-service date is currently expected to occur in the first half of 2016.

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Recovery of the Kemper IGCC costs subject to the cost cap and the Cost Cap Exceptions remain subject to review and approval by the Mississippi PSC. The Company's Kemper IGCC 2010 project estimate, current cost estimate (which includes the impacts of the Court's decision), and actual costs incurred as of December 31, 2014, as adjusted for the Court's decision, are as follows:

Cost Category	2010 Project Estimate[f]	Current Estimate	Actual Costs at 12/31/2014
	(in billions)		
Plant Subject to Cost Cap[a]	$2.40	$4.93	$4.23
Lignite Mine and Equipment	0.21	0.23	0.23
CO_2 Pipeline Facilities	0.14	0.11	0.10
AFUDC[b][c]	0.17	0.63	0.45
Combined Cycle and Related Assets Placed in Service – Incremental[d]	—	0.02	0.00
General Exceptions	0.05	0.10	0.07
Deferred Costs[c][e]	—	0.18	0.12
Total Kemper IGCC[a][c]	$2.97	$6.20	$5.20

(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. The Current Estimate and Actual Costs include non-incremental operating and maintenance costs related to the combined cycle and associated common facilities placed in service on August 9, 2014 that are subject to the $2.88 billion cost cap and excludes post-in-service costs for the lignite mine. See "Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order" for additional information.

(b) The Company's original estimate included recovery of financing costs during construction rather than the accrual of AFUDC. This approach was not approved by the Mississippi PSC in 2012 as described in "Rate Recovery of Kemper IGCC Costs."

(c) Amounts in the Current Estimate reflect estimated costs through March 31, 2016.

(d) Incremental operating and maintenance costs related to the combined cycle and associated common facilities placed in service on August 9, 2014, net of costs related to energy sales. See "Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order" for additional information.

(e) The 2012 MPSC CPCN Order approved deferral of non-capital Kemper IGCC-related costs during construction as described in "Rate Recovery of Kemper IGCC Costs – Regulatory Assets and Liabilities."

(f) The 2010 Project Estimate is the certificated cost estimate adjusted to include the certificated estimate for the CO_2 pipeline facilities which was approved in 2011 by the Mississippi PSC.

Of the total costs, including post-in-service costs for the lignite mine, incurred as of December 31, 2014, $3.04 billion was included in property, plant, and equipment (which is net of the DOE Grants and estimated probable losses of $2.05 billion), $1.8 million in other property and investments, $44.7 million in fossil fuel stock, $32.5 million in materials and supplies, $147.7 million in other regulatory assets, $11.6 million in other deferred charges and assets, and $23.6 million in AROs in the balance sheet, with $1.1 million previously expensed.

The Company does not intend to seek any rate recovery or joint owner contributions for any costs related to the construction of the Kemper IGCC that exceed the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions. The Company recorded pre-tax charges to income for revisions to the cost estimate of $868.0 million ($536.0 million after tax), $1.10 billion ($680.5 million after tax), and $78.0 million ($48.2 million after tax) in 2014, 2013 and 2012, respectively. The increases to the cost estimate in 2014 primarily reflected costs related to extension of the project's schedule to ensure the required time for start-up activities and operational readiness, completion of construction, additional resources during start-up, and ongoing construction support during start-up and commissioning activities. The current estimate includes costs through March 31, 2016. Any further extension of the in-service date is currently estimated to result in additional base costs of approximately $25 million to $30 million per month, which includes maintaining necessary levels of start-up labor, materials, and fuel, as well as operational resources required to execute start-up and commissioning activities. Any further extension of the in-service date with respect to the Kemper IGCC would also increase costs for the Cost Cap Exceptions, which are not subject to the $2.88 billion cost cap established by the Mississippi PSC. These costs include AFUDC, which is currently estimated to total approximately $13 million per month, as well as carrying costs and operating expenses on Kemper IGCC assets placed in service and consulting and legal fees, which are being deferred as regulatory assets and are estimated to total approximately $7 million per month.

Any further cost increases and/or extensions of the in-service date with respect to the Kemper IGCC may result from factors including, but not limited to, labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, non-performance under construction or other agreements,

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operational readiness, including specialized operator training and required site safety programs, unforeseen engineering or design problems, start-up activities for this first-of-a-kind technology (including major equipment failure and system integration), and/or operational performance (including additional costs to satisfy any operational parameters ultimately adopted by the Mississippi PSC). In subsequent periods, any further changes in the estimated costs to complete construction and start-up of the Kemper IGCC subject to the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions, will be reflected in the Company's statements of operations and these changes could be material.

Rate Recovery of Kemper IGCC Costs

See "FERC Matters" for additional information regarding the Company's MRA cost-based tariff relating to recovery of a portion of the Kemper IGCC costs from the Company's wholesale customers. Rate recovery of the retail portion of the Kemper IGCC is subject to the jurisdiction of the Mississippi PSC. See Note 3 to the financial statements under "Retail Regulatory Matters – Baseload Act" for additional information. See "Income Tax Matters" herein for additional tax information related to the Kemper IGCC.

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 the Company's recovery of financing costs during the course of construction of the Kemper IGCC and the Company's recovery of costs following the date the Kemper IGCC is placed in service. 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 the Company's petition for the CPCN. The Company expects the Mississippi PSC to apply operational parameters in connection with the evaluation of the Rate Mitigation Plan (defined below) and other related proceedings during the operation of the Kemper IGCC. To the extent the Mississippi PSC determines the Kemper IGCC does not meet the operational parameters ultimately adopted by the Mississippi PSC or the Company incurs additional costs to satisfy such parameters, there could be a material adverse impact on the Company's financial statements.

2013 Settlement Agreement

In January 2013, the Company entered into a settlement agreement with the Mississippi PSC that, among other things, established the process for resolving matters regarding cost recovery related to the Kemper IGCC (2013 Settlement Agreement). Under the 2013 Settlement Agreement, the Company 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 2013 Settlement Agreement also allowed the Company to secure alternate financing for costs not otherwise recovered in any Mississippi PSC rate proceedings contemplated by the 2013 Settlement Agreement. The Court found the 2013 Settlement Agreement unenforceable due to a lack of public notice for the related proceedings. See "2015 Mississippi Supreme Court Decision" below for additional information.

Legislation to authorize a multi-year rate plan and legislation to provide for alternate financing through securitization of up to $1.0 billion of prudently-incurred costs was enacted into law in February 2013. The Company's intent under the 2013 Settlement Agreement was 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, which include carrying costs from the estimated in-service date until securitization is finalized and other costs not included in the Rate Mitigation Plan as approved by the Mississippi PSC.

The Court's decision did not impact the Company's ability to utilize alternate financing through securitization, the 2012 MPSC CPCN Order, or the February 2013 legislation. See "2015 Mississippi Supreme Court Decision" below for additional information.

2013 MPSC Rate Order

Consistent with the terms of the 2013 Settlement Agreement, in March 2013, the Mississippi PSC issued the 2013 MPSC Rate Order approving retail rate increases of 15% effective March 19, 2013 and 3% effective January 1, 2014, which collectively were designed to collect $156 million annually beginning in 2014. For the period from March 2013 through December 31, 2014, $257.2 million had been collected primarily to be used to mitigate customer rate impacts after the Kemper IGCC is placed in service.

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Because the 2013 MPSC Rate Order did not provide for the inclusion of CWIP in rate base as permitted by the Baseload Act, the Company continues to record AFUDC on the Kemper IGCC through the in-service date. The Company 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. The Company will continue to record AFUDC and collect and defer the approved rates through the in-service date until directed to do otherwise by the Mississippi PSC.

On August 18, 2014, the Company provided an analysis of the costs and benefits of placing the combined cycle and the associated common facilities portion of the Kemper IGCC in service, including the expected accounting treatment. The Company's analysis requested, among other things, confirmation of the Company's accounting treatment by the Mississippi PSC of the continued collection of rates as prescribed by the 2013 MPSC Rate Order, with the current recognition as revenue of the related equity return on all assets placed in service and the deferral of all remaining rate collections under the 2013 MPSC Rate Order to a regulatory liability account. See "2015 Mississippi Supreme Court Decision" for additional information regarding the decision of the Court which would discontinue the collection of, and require the refund of, all amounts previously collected under the 2013 MPSC Rate Order.

In addition, the Company's August 18, 2014 filing with the Mississippi PSC requested confirmation of the Company's accounting treatment by the Mississippi PSC of the continued accrual of AFUDC through the in-service date of the remainder of the Kemper IGCC and the deferral of operating costs for the combined cycle as regulatory assets. Under the Company's proposal, non-incremental costs that would have been incurred whether or not the combined cycle was placed in service would be included in a regulatory asset and would continue to be subject to the $2.88 billion cost cap. Additionally, incremental costs that would not have been incurred if the combined cycle had not gone into service would be included in a regulatory asset and would not be subject to the cost cap because these costs are incurred to support operation of the combined cycle. All energy revenues associated with the combined cycle variable operating and maintenance expenses would be credited to this regulatory asset. See "Regulatory Assets and Liabilities" for additional information. Any action by the Mississippi PSC that is inconsistent with the treatment requested by the Company could have a material impact on the results of operations, financial condition, and liquidity of the Company.

2015 Mississippi Supreme Court Decision

On February 12, 2015, the Court issued its decision in the legal challenge to the 2013 MPSC Rate Order filed by Thomas A. Blanton. The Court reversed the 2013 MPSC Rate Order based on, among other things, its findings that (1) the Mirror CWIP rate treatment was not provided for under the Baseload Act and (2) the Mississippi PSC should have determined the prudence of Kemper IGCC costs before approving rate recovery through the 2013 MPSC Rate Order. The Court also found the 2013 Settlement Agreement unenforceable due to a lack of public notice for the related proceedings. The Court's ruling remands the matter to the Mississippi PSC to (1) fix by order the rates that were in existence prior to the 2013 MPSC Rate Order, (2) fix no rate increases until the Mississippi PSC is in compliance with the Court's ruling, and (3) enter an order refunding amounts collected under the 2013 MPSC Rate Order. Through December 31, 2014, the Company had collected $257.2 million through rates under the 2013 MPSC Rate Order. Any required refunds would also include carrying costs. The Court's decision will become legally effective upon the issuance of a mandate to the Mississippi PSC. Absent specific instruction from the Court, the Mississippi PSC will determine the method and timing of the refund. The Company is reviewing the Court's decision and expects to file a motion for rehearing which would stay the Court's mandate until either the case is reheard and decided or seven days after the Court issues its order denying the Company's request for rehearing. The Company is also evaluating its regulatory options.

Rate Mitigation Plan

In March 2013, the Company, in compliance with the 2013 MPSC Rate Order, filed a revision to the proposed rate recovery plan with the Mississippi PSC for the Kemper IGCC for cost recovery through 2020 (Rate Mitigation Plan), which is still under review by the Mississippi PSC. The revenue requirements set forth in the Rate Mitigation Plan assume the sale of a 15% undivided interest in the Kemper IGCC to SMEPA and utilization of bonus depreciation, which currently requires that the related long-term asset be placed in service in 2015. In the Rate Mitigation Plan, the

Company 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 in March 2013, was integral to the Rate Mitigation 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 Rate Mitigation Plan, the Company proposed annual rate recovery to remain the same from 2014 through 2020, with the proposed revenue requirement approximating the forecasted cost of service for the period 2014 through 2020. Under the Company's proposal, to the extent the actual annual cost of service differs from the approved forecast for certain items, 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 2020, the Mississippi PSC

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would review the amount and, if approved, determine the appropriate method and period of disposition. See "Regulatory Assets and Liabilities" and "Income Tax Matters" for additional information.

To the extent that refunds of amounts collected under the 2013 MPSC Rate Order are required on a schedule different from the amortization schedule proposed in the Rate Mitigation Plan, the customer billing impacts proposed under the Rate Mitigation Plan would no longer be viable. See "2015 Mississippi Supreme Court Decision" above for additional information.

In the event that the Mirror CWIP regulatory liability is refunded to customers prior to the in-service date of the Kemper IGCC and is, therefore, not available to mitigate rate impacts under the Rate Mitigation Plan, the Mississippi PSC does not approve a refund schedule that facilitates rate mitigation, or the Company withdraws the Rate Mitigation Plan, the Company would seek rate recovery through alternate means, which could include a traditional rate case.

In addition to current estimated costs at December 31, 2014 of $6.20 billion, the Company anticipates that it will incur additional costs after the Kemper IGCC in-service date until the Kemper IGCC cost recovery approach is finalized. These costs include, but are not limited to, regulatory costs and additional carrying costs which could be material. Recovery of these costs would be subject to approval by the Mississippi PSC.

Prudence Reviews

The Mississippi PSC's review of Kemper IGCC costs is ongoing. On August 5, 2014, the Mississippi PSC ordered that a consolidated prudence determination of all Kemper IGCC costs be completed after the entire project has been placed in service and has demonstrated availability for a reasonable period of time as determined by the Mississippi PSC and the MPUS. The Mississippi PSC has encouraged the parties to work in good faith to settle contested issues and the Company is working to reach a mutually acceptable resolution. As a result of the Court's decision, the Company intends to request that the Mississippi PSC reconsider its prudence review schedule. See "2015 Mississippi Supreme Court Decision" for additional information.

Regulatory Assets and Liabilities

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

On August 18, 2014, the Company requested confirmation by the Mississippi PSC of the Company's authority to defer all operating expenses associated with the operation of the combined cycle subject to review of such costs by the Mississippi PSC. In addition, the Company is authorized to accrue carrying costs on the unamortized balance of such regulatory assets at a rate and in a manner to be determined by the Mississippi PSC in future cost recovery mechanism proceedings. As of December 31, 2014, the regulatory asset balance associated with the Kemper IGCC was $147.7 million. The projected balance at March 31, 2016 is estimated to total approximately $269.8 million. The amortization period of 40 years proposed by the Company for any such costs approved for recovery remains subject to approval by the Mississippi PSC.

The 2013 MPSC Rate Order approved retail rate increases of 15% effective March 19, 2013 and 3% effective January 1, 2014, which collectively were designed to collect $156 million annually beginning in 2014. On February 12, 2015, the Court ordered the Mississippi PSC to refund Mirror CWIP and to fix by order the rates that were in existence prior to the 2013 MPSC Rate Order. The Company is deferring the collections under the approved rates in the Mirror CWIP regulatory liability until otherwise directed by the Mississippi PSC. The Company is also accruing carrying costs on the unamortized balance of the Mirror CWIP regulatory liability for the benefit of retail customers. As of December 31, 2014, the balance of the Mirror CWIP regulatory liability, including carrying costs, was $270.8 million.

See "2015 Mississippi Supreme Court Decision" for additional information.

See Note 1 to the financial statements under "Regulatory Assets and Liabilities" for additional information.
Lignite Mine and CO_2 Pipeline Facilities
In conjunction with the Kemper IGCC, the Company will own the lignite mine and equipment and has acquired and will continue to acquire mineral reserves located around the Kemper IGCC site. The mine started commercial operation in June 2013.
In 2010, the Company executed a 40-year management fee contract with Liberty Fuels Company, LLC (Liberty Fuels), a wholly-owned subsidiary of The North American Coal Corporation, which developed, constructed, and is operating and managing the mining operations. The contract with Liberty Fuels is effective through the end of the mine reclamation. As the mining permit holder, Liberty Fuels has a legal obligation to perform mine reclamation and the Company has a contractual obligation to fund all

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reclamation activities. In addition to the obligation to fund the reclamation activities, the Company currently provides working capital support to Liberty Fuels through cash advances for capital purchases, payroll, and other operating expenses. See Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" and "Variable Interest Entities" for additional information.

In addition, the Company has constructed and will operate the CO_2 pipeline for the planned transport of captured CO_2 for use in enhanced oil recovery. The Company has entered into agreements with Denbury Onshore (Denbury), a subsidiary of Denbury Resources Inc., and Treetop Midstream Services, LLC (Treetop), an affiliate of Tellus Operating Group, LLC and a subsidiary of Tengrys, LLC, pursuant to which Denbury will purchase 70% of the CO_2 captured from the Kemper IGCC and Treetop will purchase 30% of the CO_2 captured from the Kemper IGCC. The agreements with Denbury and Treetop provide termination rights in the event that the Company does not satisfy its contractual obligation with respect to deliveries of captured CO_2 by May 11, 2015. While the Company has received no indication from either Denbury or Treetop of their intent to terminate their respective agreements, any termination could result in a material reduction in future chemical product sales revenues and could have a material financial impact on the Company to the extent the Company is not able to enter into other similar contractual arrangements. The ultimate outcome of these matters cannot be determined at this time.

Proposed Sale of Undivided Interest to SMEPA

In 2010, the Company and SMEPA entered into an APA whereby SMEPA agreed to purchase a 17.5% undivided interest in the Kemper IGCC. In 2012, the Mississippi PSC approved the sale and transfer of the 17.5% undivided interest in the Kemper IGCC to SMEPA. Later in 2012, the Company and SMEPA signed an amendment to the APA whereby SMEPA reduced its purchase commitment percentage from a 17.5% to a 15% undivided interest in the Kemper IGCC. In March 2013, the Company and SMEPA signed an amendment to the APA whereby the Company and SMEPA agreed to amend the power supply agreement entered into by the parties in 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 2011 power supply agreement were $16.7 million in 2014. In December 2013, the Company and SMEPA agreed to extend SMEPA's option to purchase through December 31, 2014.

By letter agreement dated October 6, 2014, the Company and SMEPA agreed in principle on certain issues related to SMEPA's proposed purchase of a 15% undivided interest in the Kemper IGCC. The letter agreement contemplated certain amendments to the APA, which the parties anticipated to be incorporated into the APA on or before December 31, 2014. The parties agreed to further amend the APA as follows: (1) the Company agreed to cap at $2.88 billion the portion of the purchase price payable for development and construction costs, net of the Cost Cap Exceptions, title insurance reimbursement, and AFUDC and/or carrying costs through the Closing Commitment Date (defined below); (2) SMEPA agreed to close the purchase within 180 days after the date of the execution of the amended APA or before the Kemper IGCC in-service date, whichever occurs first (Closing Commitment Date), subject only to satisfaction of certain conditions; and (3) AFUDC and/or carrying costs will continue to be accrued on the capped development and construction costs, the Cost Cap Exceptions, and any operating costs, net of revenues until the amended APA is executed by both parties, and thereafter AFUDC and/or carrying costs and payment of interest on SMEPA's deposited money will be suspended and waived provided closing occurs by the Closing Commitment Date. The letter agreement also provided for certain post-closing adjustments to address any differences between the actual and the estimated amounts of post-in-service date costs (both expenses and capital) and revenue credits for those portions of the Kemper IGCC previously placed in service.

By letter dated December 18, 2014, SMEPA notified the Company that SMEPA decided not to extend the estimated closing date in the APA or revise the APA to include the contemplated amendments; however, both parties agree that the APA will remain in effect until closing or until either party gives notice of termination.

The closing of this transaction is also conditioned upon execution of a joint ownership and operating agreement, the absence of material adverse effects, receipt of all construction permits, and appropriate regulatory approvals, as well as SMEPA's receipt of Rural Utilities Service (RUS) funding. In 2012, SMEPA received a conditional loan commitment from RUS for the purchase.

In 2012, on January 2, 2014, and on October 9, 2014, the Company received $150 million, $75 million, and $50 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, the Company would be required to refund the deposits upon the termination of the APA or within 15 days of a request by SMEPA for a full or partial refund. Given the interest-bearing nature of the deposits and SMEPA's ability to request a refund, the deposits have been presented as a current liability in the balance sheet and as financing proceeds in the statement of cash flow. In July 2013, Southern Company entered into an agreement with SMEPA

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under which Southern Company has agreed to guarantee the obligations of the Company with respect to any required refund of the deposits.

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

Income Tax Matters

See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information about the Kemper IGCC. The ultimate outcome of these tax matters cannot be determined at this time.

Bonus Depreciation

On December 19, 2014, the Tax Increase Prevention Act of 2014 (TIPA) was signed into law. The TIPA retroactively extended several tax credits through 2014 and extended 50% bonus depreciation for property placed in service in 2014 (and for certain long-term production-period projects to be placed in service in 2015). The extension of 50% bonus depreciation had a positive impact on the Company's cash flows and combined with bonus depreciation allowed in 2014 under the American Taxpayer Relief Act of 2012, resulted in approximately $130 million of positive cash flows related to the combined cycle and associated common facilities portion of the Kemper IGCC for the 2014 tax year. The estimated cash flow benefit of bonus depreciation related to TIPA is expected to be approximately $45 million to $50 million for the 2015 tax year.

Investment Tax Credits

The IRS allocated $279.0 million (Phase II) of Internal Revenue Code of 1986, as amended (Internal Revenue Code), Section 48A tax credits to the Company in connection with the Kemper IGCC. Through December 31, 2014, the Company had recorded tax benefits totaling $276.4 million for the Phase II credits, of which approximately $210 million had been utilized through that date. These credits 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. The Company currently expects to place the Kemper IGCC in service in the first half of 2016. In addition, a portion of the Phase II tax credits will be subject to recapture upon completion of SMEPA's proposed purchase of an undivided interest in the Kemper IGCC as described above.

Section 174 Research and Experimental Deduction

Southern Company, on behalf of the Company, reduced tax payments for 2014 and included in its 2013 consolidated federal income tax return deductions for research and experimental (R&E) expenditures related to the Kemper IGCC. Due to the uncertainty related to this tax position, the Company recorded an unrecognized tax benefit of approximately $160 million as of December 31, 2014. See Note 5 to the financial statements under "Unrecognized Tax Benefits" for additional information.

Other Matters

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

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

In February 2013, the Company submitted a claim under the Deepwater Horizon Economic and Property Damages Settlement Agreement associated with the oil spill that occurred in April 2010 in the Gulf of Mexico. The ultimate outcome of this matter cannot be determined at this time.

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Sierra Club Settlement Agreement
On August 1, 2014, the Company entered into the Sierra Club Settlement Agreement that, among other things, requires the Sierra Club to dismiss or withdraw all pending legal and regulatory challenges of the Kemper IGCC and the scrubber project at Plant Daniel Units 1 and 2. In addition, the Sierra Club agreed to refrain from initiating, intervening in, and/or challenging certain legal and regulatory proceedings for the Kemper IGCC, including, but not limited to, the prudence review, and Plant Daniel for a period of three years from the date of the Sierra Club Settlement Agreement. On August 4, 2014, the Sierra Club filed all of the required motions necessary to dismiss or withdraw all appeals associated with certification of the Kemper IGCC and the Plant Daniel Units 1 and 2 scrubber project, which the applicable courts subsequently granted.
Under the Sierra Club Settlement Agreement, the Company agreed to, among other things, fund a $15 million grant payable over a 15-year period for an energy efficiency and renewable program and contribute $2 million to a conservation fund. In accordance with the Sierra Club Settlement Agreement, the Company paid $7 million in 2014, recognized in other income (expense), net in the statement of operations. In addition, and consistent with the Company's ongoing evaluation of recent environmental rules and regulations, the Company agreed to retire, repower with natural gas, or convert to an alternative non-fossil fuel source Plant Sweatt Units 1 and 2 (80 MWs) no later than December 2018. The Company also agreed that it would cease burning coal and other solid fuel at Plant Watson Units 4 and 5 (750 MWs) and begin operating those units solely on natural gas no later than April 2015, and cease burning coal and other solid fuel at Plant Greene County Units 1 and 2 (200 MWs) and begin operating those units solely on natural gas no later than April 2016. See Note 3 under "Retail Regulatory Matters – Environmental Compliance Overview Plan" for additional information.
ACCOUNTING POLICIES
Application of Critical Accounting Policies and Estimates
The Company prepares its 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 the Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has reviewed and discussed the following critical accounting policies and estimates with the Audit Committee of Southern Company's Board of Directors.
Electric Utility Regulation
The Company is subject to retail regulation by the Mississippi PSC and wholesale regulation by the FERC. These regulatory agencies set the rates the Company is permitted to charge customers based on allowable costs. As a result, the Company applies accounting standards which require the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of the accounting standards has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the Company; therefore, the accounting estimates inherent in specific costs such as depreciation and pension and postretirement benefits have less of a direct impact on the Company's results of operations and financial condition than they would on a non-regulated company.
As reflected in Note 1 to the financial statements, significant regulatory assets and liabilities have been recorded. Management reviews the ultimate recoverability of these regulatory assets and any requirement to refund these regulatory liabilities based on applicable regulatory guidelines and GAAP. However, adverse legislative, judicial, or regulatory actions could materially impact the amounts of such regulatory assets and liabilities and could adversely impact the Company's financial statements.

Contingent Obligations

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

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Unbilled Revenues
Revenues related to the retail sale of electricity are recorded when electricity is delivered to customers. However, the determination of KWH sales to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, amounts of electricity delivered to customers, but not yet metered and billed, are estimated. Components of the unbilled revenue estimates include total KWH territorial supply, total KWH billed, estimated total electricity lost in delivery, and customer usage. These components can fluctuate as a result of a number of factors including weather, generation patterns, power delivery volume, and other operational constraints. These factors can be unpredictable and can vary from historical trends. As a result, the overall estimate of unbilled revenues could be significantly affected, which could have a material impact on the Company's results of operations.
Pension and Other Postretirement Benefits
The Company's calculation of pension and other postretirement benefits expense is dependent on a number of assumptions. These assumptions include discount rates, healthcare cost trend rates, expected long-term return on plan assets, mortality rates, expected salary and wage increases, and other factors. Components of pension and other postretirement benefits expense include interest and service cost on the pension and other postretirement benefit plans, expected return on plan assets, and amortization of certain unrecognized costs and obligations. Actual results that differ from the assumptions utilized are accumulated and amortized over future periods and, therefore, generally affect recognized expense and the recorded obligation in future periods. While the Company believes that the assumptions used are appropriate, differences in actual experience or significant changes in assumptions would affect its pension and other postretirement benefits costs and obligations.
Key elements in determining the Company's pension and other postretirement benefit expense in accordance with GAAP are the expected long-term return on plan assets and the discount rate used to measure the benefit plan obligations and the periodic benefit plan expense for future periods. The expected long-term return on postretirement benefit plan assets is based on the Company's investment strategy, historical experience, and expectations for long-term rates of return that consider external actuarial advice. The Company determines the long-term return on plan assets by applying the long-term rate of expected returns on various asset classes to the Company's target asset allocation. The Company discounts the future cash flows related to its postretirement benefit plans using a single-point discount rate developed from the weighted average of market-observed yields for high quality fixed income securities with maturities that correspond to expected benefit payments.
For purposes of its December 31, 2014 measurement date, the Company adopted new mortality tables for its pension plans and retiree life and medical plans, which reflect increased life expectancies in the U.S. The adoption of new mortality tables increased the projected benefit obligations for the Company's pension plans and other postretirement benefit plans by approximately $30.2 million and $5.2 million, respectively. The adoption of new mortality tables will increase net periodic costs related to the Company's pension plans and other postretirement benefit plans in 2015 by $4.1 million and $0.6 million, respectively.
A 25 basis point change in any significant assumption (discount rate, salaries, or long-term return on plan assets) would result in a $1.8 million or less change in total annual benefit expense and a $22.7 million or less change in projected obligations.
Allowance for Funds Used During Construction
In accordance with regulatory treatment, the Company records AFUDC, which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently from such allowance, AFUDC increases the revenue requirement over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in the calculation of taxable income. The average annual AFUDC rate was 6.91%, 6.89%, and 7.04% for the years ended December 31, 2014, 2013, and 2012, respectively. The AFUDC rate is applied to CWIP consistent with jurisdictional regulatory treatment. AFUDC equity was $136.4 million, $121.6 million, and $64.8 million in 2014, 2013, and 2012,

respectively.

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

During 2014, the Company further extended the scheduled in-service date for the Kemper IGCC to the first half of 2016 and revised its cost estimate to complete construction and start-up of the Kemper IGCC to an amount that exceeds the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions. The Company does not intend to seek any rate recovery or any joint owner contributions for any costs related to the construction of the Kemper IGCC that exceed the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions. As a result of the revisions to the cost estimate, the Company recorded total pre-tax charges to income for the estimated probable losses on the Kemper IGCC of $70.0 million ($43.2 million after tax) in the fourth quarter 2014, $418.0 million ($258.1 million after tax) in the third quarter 2014, $380.0 million ($234.7 million after tax) in the first quarter 2014, $40.0 million ($24.7 million

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after tax) in the fourth quarter 2013, $150.0 million ($92.6 million after tax) in the third quarter 2013, $450.0 million ($277.9 million after tax) in the second quarter 2013, $462.0 million ($285.3 million after tax) in the first quarter 2013, and $78.0 million ($48.2 million after tax) in the fourth quarter 2012. In the aggregate, the Company has incurred charges of $2.05 billion ($1.26 billion after tax) as a result of changes in the cost estimate for the Kemper IGCC through December 31, 2014.

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

The Company's revised cost estimate includes costs through March 31, 2016. Any further extension of the in-service date is currently estimated to result in additional base costs of approximately $25 million to $30 million per month, which includes maintaining necessary levels of start-up labor, materials, and fuel, as well as operational resources required to execute start-up and commissioning activities. Any further extension of the in-service date with respect to the Kemper IGCC would also increase costs for the Cost Cap Exceptions, which are not subject to the $2.88 billion cost cap established by the Mississippi PSC. These costs include AFUDC, which is currently estimated to total approximately $13 million per month, as well as carrying costs and operating expenses on Kemper IGCC assets placed in service and consulting fees and legal fees which are being deferred as regulatory assets and are estimated to total approximately $7 million per month.

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

Recently Issued Accounting Standards

On May 28, 2014, the Financial Accounting Standards Board issued ASC 606, Revenue from Contracts with Customers. ASC 606 revises the accounting for revenue recognition and is effective for fiscal years beginning after December 15, 2016. The Company continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.

FINANCIAL CONDITION AND LIQUIDITY

Overview

Earnings in 2014 and 2013 were negatively affected by revisions to the cost estimate for the Kemper IGCC and by the Court’s decision to reverse the 2013 MPSC Rate order; however, the Company's financial condition remained stable at December 31, 2014 and December 31, 2013 as a result of capital contributions to the Company by Southern Company. The Company's cash requirements primarily consist of funding debt maturities, including $775 million of bank loans maturing in 2015, ongoing operations, capital expenditures, and the potential requirement to refund amounts collected under the 2013 MPSC Rate Order ($257.2 million through December 31, 2014) and additional amounts for associated carrying costs. See FUTURE EARNINGS POTENTIAL – Integrated Coal Gasification Combined Cycle – "Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order" and " – 2015 Mississippi Supreme Court Decision" herein for additional information. For the three-year period from 2015 through 2017, the Company's capital expenditures and debt maturities are expected to materially exceed operating cash flows. In addition to the Kemper IGCC, projected capital expenditures in that period include investments to maintain existing generation facilities, including the Plant Daniel scrubber project, to add environmental equipment for existing generating units, to add or change fuel sources for certain existing units, and to expand and improve transmission and distribution facilities. Through December 31, 2014, the Company has incurred non-recoverable cash expenditures of $1.3 billion and is expected to incur approximately $702 million in additional non-recoverable cash expenditures through completion of the Kemper IGCC.

In 2014, the Company received $450.0 million in equity contributions and a $220.0 million loan from Southern Company which was repaid on September 29, 2014. In January 2015, the Company received an additional $75.0 million in equity contributions from Southern Company. The Company is currently negotiating to refinance its maturing bank loans and to obtain additional bank loans. The Company also intends to utilize cash from operations and commercial paper and lines of credit as market conditions

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permit, as well as, under certain circumstances, equity contributions and/or loans from Southern Company, to fund the Company's short-term capital needs.
See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.
The Company's investments in the qualified pension plan increased in value as of December 31, 2014 as compared to December 31, 2013. In December 2014, the Company voluntarily contributed $33 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2015.
Net cash provided from operating activities totaled $734.4 million for 2014, an increase of $286.8 million as compared to the corresponding period in 2013. The increase in net cash provided from operating activities was primarily due to deferred income taxes and Mirror CWIP, net of the Kemper IGCC regulatory deferral, partially offset by a decrease in ITCs received related to the Kemper IGCC, an increase in prepaid income taxes, increases in fossil fuel stock, and an increase in regulatory assets associated with the Kemper IGCC. Net cash provided from operating activities totaled $447.6 million for 2013, an increase of $212.2 million as compared to the corresponding period in 2012. The increase in net cash provided from operating activities was primarily due to an increase in ITCs received related to the Kemper IGCC, increases in rate recovery related to the Kemper IGCC, and decreases in fossil fuel stock, partially offset by a decrease in over-recovered regulatory clause revenues and an increase in regulatory assets associated with the Kemper IGCC.
Net cash used for investing activities totaled $1.3 billion for 2014 primarily due to gross property additions primarily related to the Kemper IGCC and the Plant Daniel scrubber project. Net cash used for investing activities totaled $1.6 billion for 2013 primarily due to gross property additions primarily related to the Kemper IGCC and the Plant Daniel scrubber project, partially offset by proceeds from asset sales.
Net cash provided from financing activities totaled $592.6 million in 2014 primarily due to capital contributions from Southern Company, long-term debt financings, and the receipts of interest bearing refundable deposits related to a pending asset sale, partially offset by redemptions of long-term debt. Net cash provided from financing activities totaled $1.2 billion in 2013 primarily due to an increase in capital contributions from Southern Company and an increase in long-term debt financings, partially offset by redemptions of long-term debt.
Significant balance sheet changes as of December 31, 2014 compared to 2013 included an increase in securities due within one year of $763.9 million and a decrease in long-term debt of $536.6 million, primarily due to bank loans maturing in 2015, as well as an increase in the interest-bearing refundable deposit from SMEPA of $125.0 million. See "Financing Activities" herein for additional information. Total property, plant, and equipment increased $416.6 million and other regulatory assets, deferred increased $184.8 million primarily due to the Kemper IGCC and results of an actuarial study. See "Integrated Coal Gasification Combined Cycle" herein for additional information. Other regulatory liabilities, deferred decreased $81.3 million and Mirror CWIP increased $270.8 million primarily due to the reclassification of Kemper regulatory liabilities. Additional changes included an increase in accrued income taxes of $136.9 million primarily due to R&E tax deductions, an increase in prepaid income taxes of $155.9 million primarily due to ITCs related to the Kemper IGCC and an increase in taxes on Mirror CWIP, a net increase in accumulated deferred income taxes of $194.7 million primarily related to the Kemper combined cycle and associated common facilities placed in service on August 9, 2014 offset by the estimated probable loss on the Kemper IGCC, an increase in employee benefit obligations of $53.1 million, and an increase in deferred charges related to income taxes of $81.8 million. See Note 2 and Note 5 to the financial statements for additional information. Total common stockholder's equity decreased $92.3 million primarily due to the estimated probable loss on the Kemper IGCC partially offset by the receipt of $450.0 million in capital contributions from Southern Company.
The Company's ratio of common equity to total capitalization, including long-term debt due within one year, was 46.1% in 2014 and 49.6% in 2013. See Note 6 to the financial statements for additional information.
Sources of Capital

Except as described herein, the Company plans to obtain the funds required for construction and other purposes from operating cash flows, security issuances, term loans, and/or short-term debt, as well as, under certain circumstances, equity contributions and/or loans from Southern Company. Operating cash flows would be adversely impacted by $156 million annually with the removal of rates implemented under the 2013 MPSC Rate Order. The amount, type, and timing of future financings will depend upon regulatory approval, prevailing market conditions, and other factors, which may include resolution of Kemper IGCC cost recovery. See "Capital Requirements and Contractual Obligations" herein for additional information. See FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order" and " – 2015 Mississippi Supreme Court Decision" included herein for additional information.

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The Company received $245.3 million of DOE Grants in prior years that were used for the construction of the Kemper IGCC. An additional $25 million of DOE Grants is expected to be received for commercial operation of the Kemper IGCC. In addition, see FUTURE EARNINGS POTENTIAL – "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 Company is subject to regulatory approval by the FERC. Additionally, with respect to the public offering of securities, the Company files registration statements with the SEC under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the FERC, as well as the amounts registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in raising capital. Any future financing through secured debt would also require approval by the Mississippi PSC.

See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of the Company are not commingled with funds of any other company in the Southern Company system.

As of December 31, 2014, the Company's current liabilities exceeded current assets by approximately $1.3 billion primarily due to $775 million of bank loans maturing in 2015, an interest-bearing refundable deposit from SMEPA, and the potential Mirror CWIP refund. The Company is currently negotiating to refinance its maturing bank loans and to obtain additional bank loans. The Company also intends to utilize cash from operations, and commercial paper and lines of credit as market conditions permit, as well as, under certain circumstances, equity contributions and/or loans from Southern Company, to fund the Company's short-term capital needs. See FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs" herein for additional information.

At December 31, 2014, the Company had approximately $132.5 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2014 were as follows:

Expires				Executable Term-Loans		Due Within One Year	
2015	2016	Total	Unused	One Year	Two Years	Term Out	No Term Out
(in millions)							
$135	$165	$300	$300	$25	$40	$65	$70

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

The Company expects to renew its credit arrangements, as needed prior to expiration.

Most of these bank credit arrangements contain covenants that limit debt levels and typically contain cross default provisions to other indebtedness (including guarantee obligations) of the Company. Such cross default provisions to other indebtedness would trigger an event of default if the Company defaulted on indebtedness or guarantee obligations over a specified threshold. The Company is in compliance with all such covenants. None of the bank credit arrangements contain material adverse change clauses at the time of borrowing.

A portion of the $300 million unused credit arrangements with banks is allocated to provide liquidity support to the Company's variable rate pollution control revenue bonds and commercial paper borrowings. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2014 was $40.1 million.

The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of the Company and the other traditional operating companies. Proceeds from such issuances for the benefit of the Company are loaned directly to the Company. The obligations of each traditional operating company under these arrangements are several and there is no cross affiliate credit support.

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The Company had no short-term borrowings in 2012 and 2014. Details of short-term borrowing for 2013 were as follows:

	Commercial Paper at the End of the Period		Commercial Paper During the Period [(a)]		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		(in millions)		(in millions)
December 31, 2013	$—	—%	$23	0.2%	$148

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

Financing Activities

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

Bank Term Loans

In January 2014, the Company 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 the proceeds were used for working capital and other general corporate purposes, including the Company's continuous construction program.

This and other bank loans and the other revenue bonds described below 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, other hybrid securities, and securitized debt relating to the securitization of certain costs of the Kemper IGCC. At December 31, 2014, the Company was in compliance with its debt limits.

In addition, this and other bank loans and the other revenue bonds described below contain cross default provisions to other debt (including guarantee obligations) that would be triggered if the Company defaulted on debt above a specified threshold. The Company is currently in compliance with all such covenants.

Other Revenue Bonds

In May 2014 and August 2014, the Mississippi Business Finance Corporation (MBFC) issued $12.3 million and $10.5 million, respectively, aggregate principal amount of MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2013A for the benefit of the Company and proceeds were used to reimburse the Company for the cost of the acquisition, construction, equipping, installation, and improvement of certain equipment and facilities for the lignite mining facility related to the Kemper IGCC. In December 2014, the MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2013A of $22.87 million and Series 2013B of $11.25 million were paid at maturity.

Other Obligations

In 2012, January 2014, and October 2014, the Company received $150 million, $75 million, and $50 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 the Company's AFUDC rate adjusted for income taxes, which was 10.134% per annum for 2014, 9.932% per annum for 2013, and 9.967% per annum for 2012, and are refundable to SMEPA upon termination of the APA related to such purchase or within 15 days of a request by SMEPA for a full or partial refund. In July 2013, Southern Company entered into an agreement with SMEPA under which Southern Company has agreed to guarantee the obligations of the Company with respect to any required refund of the deposits.

In May 2014, the Company issued a 19-month floating rate promissory note to Southern Company for a loan bearing interest based on one-month LIBOR. This loan was for $220 million aggregate principal amount and the proceeds were used for working capital and other general corporate purposes, including the Company's construction program. This loan was repaid on September 29, 2014.

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade.

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There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to below BBB- and/or Baa3. These contracts are for physical electricity sales, fuel transportation and storage, and energy price risk management. At December 31, 2014, the maximum amount of potential collateral requirements under these contracts at a rating below BBB- and/or Baa3 equaled approximately $280 million. Included in these amounts are certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact the Company's ability to access capital markets, particularly the short-term debt market and the variable rate pollution control revenue bond market.
Subsequent to December 31, 2014, Moody's affirmed the senior unsecured debt rating of the Company and revised the ratings outlook for the Company from stable to negative.
Market Price Risk
Due to cost-based rate regulation and other various cost recovery mechanisms, the Company continues to have limited exposure to market volatility in interest rates, foreign currency exchange rates, commodity fuel prices, and prices of electricity. To manage the volatility attributable to these exposures, the Company nets the exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques that include, but are not limited to, market valuation, value at risk, stress testing, and sensitivity analysis.
To mitigate future exposure to a change in interest rates, the Company may enter into derivatives that have been designated as hedges. The weighted average interest rate on $815 million of long-term variable interest rate exposure at December 31, 2014 was 0.96%. If the Company sustained a 100 basis point change in interest rates for all long-term variable interest rate exposure, the change would affect annualized interest expense by approximately $8 million at January 1, 2015. See Note 1 to the financial statements under "Financial Instruments" and Note 10 to the financial statements for additional information.
To mitigate residual risks relative to movements in electricity prices, the Company enters into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, financial hedge contracts for natural gas purchases. The Company continues to manage retail fuel-hedging programs implemented per the guidelines of the Mississippi PSC and wholesale fuel-hedging programs under agreements with wholesale customers. The Company had no material change in market risk exposure for the year ended December 31, 2014 when compared to the year ended December 31, 2013.
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:

	2014 Changes	2013 Changes
	Fair Value	
	(in thousands)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	$(5,478)	$(16,927)
Contracts realized or settled	(2,655)	11,271
Current period changes[(a)]	(37,231)	178
Contracts outstanding at the end of the period, assets (liabilities), net	$(45,364)	$(5,478)

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

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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The net hedge volumes of energy-related derivative contracts, all of which are natural gas swaps, for the years ended December 31 were as follows:

	2014	2013
	mmBtu Volume (in thousands)	
Total hedge volume	54,220	56,440

The weighted average swap contract cost above market prices was approximately $0.84 per mmBtu as of December 31, 2014 and $0.10 per mmBtu as of December 31, 2013. There were no options outstanding as of the reporting periods presented. The costs associated with natural gas hedges are recovered through the Company's ECMs.

At December 31, 2014 and 2013, substantially all of the Company's energy-related derivative contracts were designated as regulatory hedges and were related to the Company's fuel-hedging program. Therefore, gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the ECM clause. Gains and losses on energy-related derivatives that are designated as cash flow hedges are used to hedge anticipated purchases and sales and are initially deferred in OCI before being recognized in income in the same period as the hedged transaction. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of operations as incurred and were not material for any year presented. The pre-tax gains and losses reclassified from OCI to revenue and fuel expense were not material for any period presented and are not expected to be material for 2015.

The Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. See Note 9 to the financial statements for further discussion of fair value measurements. The maturities of the energy-related derivative contracts, which are all Level 2 of the fair value hierarchy, at December 31, 2014 were as follows:

	Fair Value Measurements December 31, 2014			
	Total Fair Value	Maturity Year 1	Years 2&3	Years 4&5
	(in thousands)			
Level 1	$—	$—	$—	$—
Level 2	(45,364)	(26,227)	(18,620)	(517)
Level 3	—	—	—	—
Fair value of contracts outstanding at end of period	$(45,364)	$(26,227)	$(18,620)	$(517)

The Company is exposed to market price risk in the event of nonperformance by counterparties to the energy-related derivative contracts. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Note 1 to the financial statements under "Financial Instruments" and Note 10 to the financial statements.

Capital Requirements and Contractual Obligations

The construction program of the Company is currently estimated to be $1.0 billion for 2015, $328 million for 2016, and $221 million for 2017, which includes expenditures related to the construction of the Kemper IGCC of $801 million in 2015 and $132 million in 2016. The amounts related to the construction and start-up of the Kemper IGCC exclude SMEPA's proposed acquisition of a 15% ownership share of the Kemper IGCC for approximately $596 million (including construction costs for all prior periods relating to its proposed ownership interest). Capital expenditures to comply with environmental statutes and regulations included in these estimated amounts are $94 million, $25 million, and $35 million for 2015, 2016, and 2017, respectively. These estimated amounts also include capital expenditures covered under long-term service agreements. These estimated expenditures do not include any potential compliance costs that may arise from the EPA's proposed rules that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. See "Global Climate Issues" for additional information.

See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" and – "Integrated Coal Gasification Combined Cycle" for additional information.

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; storm impacts; changes in environmental statutes and regulations; the outcome of any legal challenges to the environmental rules; changes in generating plants, including unit retirements and replacements and adding or changing fuel sources at existing units, to meet regulatory requirements; changes in FERC rules and regulations; Mississippi PSC approvals; changes in the expected environmental compliance program; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; and the cost of capital. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information and further risks related to the estimated schedule and costs and rate recovery for the Kemper IGCC.
In addition, as discussed in Note 2 to the financial statements, the Company provides postretirement benefits to substantially all employees and funds trusts to the extent required by the FERC.
Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preferred stock dividends, leases, and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 1, 2, 5, 6, 7, and 10 to the financial statements for additional information.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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Contractual Obligations

	2015	2016-2017	2018-2019	After 2019	Total
	(in thousands)				
Long-term debt[(a)] —					
Principal	$775,000	$335,000	$125,000	$1,032,695	$2,267,695
Interest	77,715	132,442	120,904	723,455	1,054,516
Preferred stock dividends[(b)]	1,733	3,465	3,465	—	8,663
Financial derivative obligations[(c)]	26,270	18,623	536	—	45,429
Unrecognized tax benefits[(d)]	164,821	—	—	—	164,821
Operating leases [(e)]	3,950	2,601	—	—	6,551
Capital leases[(f)]	2,667	5,741	6,331	64,940	79,679
Purchase commitments —					
Capital[(g)]	1,016,215	491,886	—	—	1,508,101
Fuel[(h)]	266,934	299,888	255,396	289,215	1,111,433
Long-term service agreements[(i)]	27,109	23,367	20,596	128,832	199,904
Pension and other postretirement benefits plans[(j)]	6,187	13,112	—	—	19,299
Total	$2,368,601	$1,326,125	$532,228	$2,239,137	$6,466,091

(a) All amounts are reflected based on final maturity dates. The Company plans to continue to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of January 1, 2015, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk. Long-term debt excludes capital lease amounts (shown separately).
(b) Preferred stock does not mature; therefore, amounts are provided for the next five years only.
(c) For additional information, see Notes 1 and 10 to the financial statements.
(d) See Note 5 to the financial statements under "Unrecognized Tax Benefits" for additional information.
(e) See Note 7 to the financial statements for additional information.
(f) Capital lease related to a 20-year nitrogen supply agreement for the Kemper IGCC. See Note 6 to the financial statements for additional information.
(g) The Company provides estimated capital expenditures for a three-year period, including capital expenditures and compliance costs associated with environmental regulations. Estimates related to the construction and start-up of the Kemper IGCC exclude SMEPA's proposed acquisition of a 15% ownership share of the Kemper IGCC. At December 31, 2014, significant purchase commitments were outstanding in connection with the construction program. These amounts exclude capital expenditures covered under long-term service agreements, which are reflected separately. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" for additional information. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information.
(h) Includes commitments to purchase coal and natural gas, as well as the related transportation and storage. In most cases, these contracts contain provisions for price escalation, minimum purchase levels, and other financial commitments. Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected for natural gas purchase commitments have been estimated based on the New York Mercantile Exchange future prices at December 31, 2014.
(i) Long-term service agreements include price escalation based on inflation indices.
(j) The Company forecasts contributions to the pension and other postretirement benefit plans over a three-year period. The Company anticipates no mandatory contributions to the qualified pension plan during the next three years.

Amounts presented represent estimated benefit payments for the nonqualified pension plans, estimated non-trust benefit payments for the other postretirement benefit plans, and estimated contributions to the other postretirement benefit plan trusts, all of which will be made from the Company's corporate assets. See Note 2 to the financial statements for additional information related to the pension and other postretirement benefit plans, including estimated benefit payments. Certain benefit payments will be made through the related benefit plans. Other benefit payments will be made from the Company's corporate assets.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Mississippi Power Company 2014 Annual Report

Cautionary Statement Regarding Forward-Looking Statements
The Company's 2014 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail rates, economic recovery, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related compliance plans and estimated expenditures, access to sources of capital, projections for the qualified pension plan and postretirement benefit plan, financing activities, completion of construction projects, filings with state and federal regulatory authorities, impact of the TIPA, estimated sales and purchases under power sale and purchase agreements, storm damage cost recovery and repairs, and estimated construction and other plans and expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, environmental laws including regulation of water, CCR, and emissions of sulfur, nitrogen, CO_2, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, and also changes in tax and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including FERC matters, the pending EPA civil action, and IRS and state tax audits;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the last recession, population and business growth (and declines), the effects of energy conservation and efficiency measures, including from the development and deployment of alternative energy sources such as self-generation and distributed generation technologies, and any potential economic impacts resulting from federal fiscal decisions;
- available sources and costs of fuels;
- effects of inflation;
- the ability to control costs and avoid cost overruns during the development and construction of facilities, which include the development and construction of generating facilities with designs that have not been finalized or previously constructed, including changes in labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, non-performance under construction or other agreements, operational readiness, including specialized operator training and required site safety programs, unforeseen engineering or design problems, start-up activities (including major equipment failure and system integration), and/or operational performance (including additional costs to satisfy any operational parameters ultimately adopted by the Mississippi PSC);
- the ability to construct facilities in accordance with the requirements of permits and licenses, to satisfy any operational and environmental performance standards, including any PSC requirements and the requirements of tax credits and other incentives, and to integrate facilities into the Southern Company system upon completion of construction;
- investment performance of the Company's employee and retiree benefit plans;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms;
- the ability to successfully operate generating, transmission, and distribution facilities and the successful performance of necessary corporate functions;
- actions related to cost recovery for the Kemper IGCC, including actions relating to proposed securitization, Mississippi PSC approval of a rate recovery plan, including 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 assets be placed in service in 2015, and satisfaction of requirements to utilize ITCs and grants;

- Mississippi PSC review of the prudence of Kemper IGCC costs;
- the ultimate outcome and impact of the February 2015 decision of the Mississippi Supreme Court and any further legal or regulatory proceedings regarding any settlement agreement between the Company and the Mississippi PSC, the March 2013 rate order regarding retail rate increases, or the Baseload Act;

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Mississippi Power Company 2014 Annual Report

- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Company's business resulting from cyber intrusion or terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and financial market conditions and the results of financing efforts;
- changes in the Company's credit ratings, including impacts on interest rates, access to capital markets, and collateral requirements;
- the impacts of any sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on currency exchange rates, counterparty performance, and the economy in general;
- the ability of the Company to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes and other storms, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

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

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STATEMENTS OF OPERATIONS
For the Years Ended December 31, 2014, 2013, and 2012
Mississippi Power Company 2014 Annual Report

	2014	2013	2012
	(in thousands)		
Operating Revenues:			
Retail revenues	$794,643	$799,139	$747,453
Wholesale revenues, non-affiliates	322,659	293,871	255,557
Wholesale revenues, affiliates	107,210	34,773	16,403
Other revenues	18,099	17,374	16,583
Total operating revenues	1,242,611	1,145,157	1,035,996
Operating Expenses:			
Fuel	573,936	491,250	411,226
Purchased power, non-affiliates	17,848	5,752	5,221
Purchased power, affiliates	25,096	42,579	49,907
Other operations and maintenance	270,669	253,329	228,675
Depreciation and amortization	97,120	91,398	86,510
Taxes other than income taxes	79,112	80,694	79,445
Estimated loss on Kemper IGCC	868,000	1,102,000	78,000
Total operating expenses	1,931,781	2,067,002	938,984
Operating Income (Loss)	(689,170)	(921,845)	97,012
Other Income and (Expense):			
Allowance for equity funds used during construction	136,436	121,629	64,793
Interest expense, net of amounts capitalized	(45,322)	(36,481)	(40,838)
Other income (expense), net	(14,097)	(6,030)	1,264
Total other income and (expense)	77,017	79,118	25,219
Earnings (Loss) Before Income Taxes	(612,153)	(842,727)	122,231
Income taxes (benefit)	(285,205)	(367,835)	20,556
Net Income (Loss)	(326,948)	(474,892)	101,675
Dividends on Preferred Stock	1,733	1,733	1,733
Net Income (Loss) After Dividends on Preferred Stock	$(328,681)	$(476,625)	$99,942

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

STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2014, 2013, and 2012
Mississippi Power Company 2014 Annual Report

	2014	2013	2012
	(in thousands)		
Net Income (Loss)	$(326,948)	$(474,892)	$101,675
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $-, $-, and $(296) respectively	—	—	(479)
Reclassification adjustment for amounts included in net income, net of tax of $526, $526, and $411, respectively	849	849	663
Total other comprehensive income (loss)	849	849	184
Comprehensive Income (Loss)	$(326,099)	$(474,043)	$101,859

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

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STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2014, 2013, and 2012
Mississippi Power Company 2014 Annual Report

	2014	2013	2012
	(in thousands)		
Operating Activities:			
Net income (loss)	$(326,948)	$(474,892)	$101,675
Adjustments to reconcile net income (loss)			
to net cash provided from operating activities —			
Depreciation and amortization, total	104,422	92,465	86,981
Deferred income taxes	145,417	(396,400)	17,688
Investment tax credits received	(38,366)	144,036	82,464
Allowance for equity funds used during construction	(136,436)	(121,629)	(64,793)
Pension, postretirement, and other employee benefits	(28,899)	13,953	(35,425)
Hedge settlements	—	—	(15,983)
Stock based compensation expense	2,903	2,510	2,084
Regulatory assets associated with Kemper IGCC	(71,816)	(35,220)	(15,445)
Estimated loss on Kemper IGCC	868,000	1,102,000	78,000
Kemper regulatory deferral	—	90,524	—
Other, net	14,022	14,585	10,516
Changes in certain current assets and liabilities —			
-Receivables	(19,065)	(25,001)	(6,589)
-Under recovered regulatory clause revenues	(2,471)	—	—
-Fossil fuel stock	13,121	63,093	(36,206)
-Materials and supplies	(15,496)	(11,087)	(3,473)
-Prepaid income taxes	(50,457)	16,644	(3,852)
-Other current assets	(3,940)	(4,363)	(19,851)
-Other accounts payable	32,661	12,693	8,814
-Accrued interest	29,349	16,768	17,627
-Accrued taxes	39,392	11,141	13,768
-Accrued compensation	17,008	(6,382)	(183)
-Over recovered regulatory clause revenues	(17,826)	(58,979)	16,836
-Mirror CWIP	180,255	—	—
-Other current liabilities	(446)	1,109	757
Net cash provided from operating activities	734,384	447,568	235,410
Investing Activities:			
Property additions	(1,257,440)	(1,640,782)	(1,620,047)
Investment in restricted cash	(10,548)	—	—
Distribution of restricted cash	10,548	—	—
Cost of removal net of salvage	(13,418)	(10,386)	(4,355)
Construction payables	(49,532)	(50,000)	78,961
Capital grant proceeds	—	4,500	13,372
Proceeds from asset sales	—	79,020	—
Other investing activities	(19,217)	14,903	(16,706)
Net cash used for investing activities	(1,339,607)	(1,602,745)	(1,548,775)
Financing Activities:			
Proceeds —			
Capital contributions from parent company	451,387	1,077,088	702,971

Bonds — Other	22,866	42,342	51,471
Senior notes issuances	—	—	600,000
Interest-bearing refundable deposit	125,000	—	150,000
Other long-term debt issuances	470,000	475,000	50,000
Redemptions —			
Bonds — Other	(34,116)	(82,563)	—
Capital Leases	(2,539)	(697)	(633)
Senior notes	—	(50,000)	(90,000)
Other long-term debt	(220,000)	(125,000)	(115,000)
Return of paid in capital	(219,720)	(104,804)	—
Payment of preferred stock dividends	(1,733)	(1,733)	(1,733)
Payment of common stock dividends	—	(71,956)	(106,800)
Other financing activities	1,414	(2,343)	6,512
Net cash provided from financing activities	592,559	1,155,334	1,246,788
Net Change in Cash and Cash Equivalents	(12,664)	157	(66,577)
Cash and Cash Equivalents at Beginning of Year	145,165	145,008	211,585
Cash and Cash Equivalents at End of Year	$132,501	$145,165	$145,008
Supplemental Cash Flow Information:			
Cash paid (received) during the period for —			
Interest (net of $68,679, $54,118 and $32,816 capitalized, respectively)	$6,992	$20,285	$32,589
Income taxes (net of refunds)	(379,158)	(134,198)	(77,580)
Noncash transactions —			
Accrued property additions at year-end	114,469	164,863	214,863
Capital lease obligation	—	82,915	—

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

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BALANCE SHEETS
At December 31, 2014 and 2013
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Assets	2014	2013
	(in thousands)	
Current Assets:		
Cash and cash equivalents	$132,501	$145,165
Receivables —		
Customer accounts receivable	40,648	40,978
Unbilled revenues	35,494	38,895
Under recovered regulatory clause revenues	2,471	—
Other accounts and notes receivable	11,256	4,600
Affiliated companies	51,060	34,920
Accumulated provision for uncollectible accounts	(825)	(3,018)
Fossil fuel stock, at average cost	100,164	113,285
Materials and supplies, at average cost	61,582	45,347
Other regulatory assets, current	72,840	48,583
Prepaid income taxes	190,631	34,751
Other current assets	6,209	9,357
Total current assets	704,031	512,863
Property, Plant, and Equipment:		
In service	4,378,087	3,458,770
Less accumulated provision for depreciation	1,172,715	1,095,352
Plant in service, net of depreciation	3,205,372	2,363,418
Construction work in progress	2,160,646	2,586,031
Total property, plant, and equipment	5,366,018	4,949,449
Other Property and Investments	5,498	4,857
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	225,507	143,747
Other regulatory assets, deferred	385,410	200,620
Accumulated deferred income taxes	17,388	—
Other deferred charges and assets	52,876	36,673
Total deferred charges and other assets	681,181	381,040
Total Assets	$6,756,728	$5,848,209

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

BALANCE SHEETS
At December 31, 2014 and 2013
Mississippi Power Company 2014 Annual Report

Liabilities and Stockholder's Equity	2014	2013
	(in thousands)	
Current Liabilities:		
Securities due within one year	$777,667	$13,789
Interest-bearing refundable deposit	275,000	150,000
Accounts payable —		
Affiliated	85,882	70,299
Other	177,736	210,191
Customer deposits	14,970	14,379
Accrued taxes —		
Accrued income taxes	142,461	5,590
Other accrued taxes	83,686	77,958
Accrued interest	76,494	47,144
Accrued compensation	26,331	9,324
Other regulatory liabilities, current	2,164	14,480
Over recovered regulatory clause liabilities	532	18,358
Mirror CWIP	270,779	—
Other current liabilities	44,701	21,413
Total current liabilities	1,978,403	652,925
Long-Term Debt (See accompanying statements)	1,630,487	2,167,067
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	284,849	72,808
Deferred credits related to income taxes	9,370	10,191
Accumulated deferred investment tax credits	282,816	284,248
Employee benefit obligations	147,536	94,430
Asset retirement obligations	48,248	41,197
Other cost of removal obligations	165,999	156,683
Other regulatory liabilities, deferred	63,681	144,992
Other deferred credits and liabilities	28,299	14,337
Total deferred credits and other liabilities	1,030,798	818,886
Total Liabilities	4,639,688	3,638,878
Cumulative Redeemable Preferred Stock (See accompanying statements)	32,780	32,780
Common Stockholder's Equity (See accompanying statements)	2,084,260	2,176,551
Total Liabilities and Stockholder's Equity	$6,756,728	$5,848,209
Commitments and Contingent Matters (See notes)		

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

STATEMENTS OF CAPITALIZATION
At December 31, 2014 and 2013
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	2014	2013	2014	2013
	(in thousands)		(percent of total)	
Long-Term Debt:				
Long-term notes payable —				
2.35% due 2016	$300,000	$300,000		
5.60% due 2017	35,000	35,000		
5.55% due 2019	125,000	125,000		
1.63% to 5.40% due 2035-2042	680,000	680,000		
Adjustable rate (1.29% at 1/1/14) due 2014	—	11,250		
Adjustable rates (0.77% to 1.17% at 1/1/15) due 2015	775,000	525,000		
Total long-term notes payable	1,915,000	1,676,250		
Other long-term debt —				
Pollution control revenue bonds:				
5.15% due 2028	42,625	42,625		
Variable rates (0.02% to 0.06% at 1/1/15) due 2020-2028	40,070	40,070		
Plant Daniel revenue bonds (7.13%) due 2021	270,000	270,000		
Total other long-term debt	352,695	352,695		
Capitalized lease obligations	79,679	82,217		
Unamortized debt premium	62,701	71,807		
Unamortized debt discount	(1,921)	(2,113)		
Total long-term debt (annual interest requirement — $78 million)	2,408,154	2,180,856		
Less amount due within one year	777,667	13,789		
Long-term debt excluding amount due within one year	1,630,487	2,167,067	43.5 %	49.6 %
Cumulative Redeemable Preferred Stock:				
$100 par value				
Authorized — 1,244,139 shares				
Outstanding — 334,210 shares				
4.40% to 5.25% (annual dividend requirement — $1.7 million)	32,780	32,780	0.9	0.7
Common Stockholder's Equity:				
Common stock, without par value —				
Authorized — 1,130,000 shares				
Outstanding — 1,121,000 shares	37,691	37,691		
Paid-in capital	2,612,136	2,376,595		
Accumulated deficit	(558,552)	(229,871)		
Accumulated other comprehensive loss	(7,015)	(7,864)		
Total common stockholder's equity	2,084,260	2,176,551	55.6	49.7
Total Capitalization	$3,747,527	$4,376,398	100.0 %	100.0 %

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

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STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
For the Years Ended December 31, 2014, 2013, and 2012
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	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
	(in thousands)					
Balance at December 31, 2011	1,121	$37,691	$694,855	$325,568	$(8,897)	$1,049,217
Net income after dividends on preferred stock	—	—	—	99,942	—	99,942
Capital contributions from parent company	—	—	706,665	—	—	706,665
Other comprehensive income (loss)	—	—	—	—	184	184
Cash dividends on common stock	—	—	—	(106,800)	—	(106,800)
Balance at December 31, 2012	1,121	37,691	1,401,520	318,710	(8,713)	1,749,208
Net loss after dividends on preferred stock	—	—	—	(476,625)	—	(476,625)
Capital contributions from parent company	—	—	975,075	—	—	975,075
Other comprehensive income (loss)	—	—	—	—	849	849
Cash dividends on common stock	—	—	—	(71,956)	—	(71,956)
Balance at December 31, 2013	1,121	37,691	2,376,595	(229,871)	(7,864)	2,176,551
Net loss after dividends on preferred stock	—	—	—	(328,681)	—	(328,681)
Capital contributions from parent company	—	—	235,541	—	—	235,541
Other comprehensive income (loss)	—	—	—	—	849	849
Balance at December 31, 2014	1,121	$37,691	$2,612,136	$(558,552)	$(7,015)	$2,084,260

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

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1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES
General
Mississippi Power Company (the Company) is a wholly owned subsidiary of The Southern Company (Southern Company), which is the parent company of the Company and three other traditional operating companies, as well as Southern Power, SCS, SouthernLINC Wireless, Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear, and other direct and indirect subsidiaries. The traditional operating companies – Alabama Power, Georgia Power, Gulf Power, and the Company – are vertically integrated utilities providing electric service in four Southeastern states. The Company operates as a vertically integrated utility providing electricity to retail customers in southeast Mississippi and to wholesale customers in the Southeast. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary, primarily for Southern Company's investments in leveraged leases. Southern Nuclear operates and provides services to the Southern Company system's nuclear power plants.
The Company is subject to regulation by the FERC and the Mississippi PSC. The Company follows GAAP in the U.S. and complies with the accounting policies and practices prescribed by its regulatory commissions. The preparation of financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates. Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation.
Recently Issued Accounting Standards
On May 28, 2014, the Financial Accounting Standards Board issued ASC 606, Revenue from Contracts with Customers. ASC 606 revises the accounting for revenue recognition and is effective for fiscal years beginning after December 15, 2016. The Company continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.
Affiliate Transactions
The Company has an agreement with SCS under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, operations, purchasing, accounting, finance and treasury, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, and other services with respect to business and operations, construction management, and power pool transactions. Costs for these services amounted to $259.0 million, $205.0 million, and $212.7 million during 2014, 2013, and 2012, respectively. Cost allocation methodologies used by SCS prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, were approved by the SEC. Subsequently, additional cost allocation methodologies have been reported to the FERC and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies.
The Company has an agreement with Alabama Power under which the Company owns a portion of Greene County Steam Plant. Alabama Power operates Greene County Steam Plant, and the Company reimburses Alabama Power for its proportionate share of non-fuel expenditures and costs, which totaled $13.4 million, $12.5 million, and $11.7 million in 2014, 2013, and 2012, respectively. Also, the Company reimburses Alabama Power for any direct fuel purchases delivered from an Alabama Power transfer facility, which were $34.5 million, $27.1 million, and $28.1 million in 2014, 2013, and 2012, respectively. The Company also has an agreement with Gulf Power under which Gulf Power owns a portion of Plant Daniel. The Company operates Plant Daniel, and Gulf Power reimburses the Company for its proportionate share of all associated expenditures and costs, which totaled $30.5 million, $16.5 million, and $21.2 million in 2014, 2013, and 2012, respectively. See Note 4 for additional information.

The Company also provides incidental services to and receives such services from other Southern Company subsidiaries which are generally minor in duration and amount. Except as described herein, the Company neither provided nor received any material services to or from affiliates in 2014 or 2013. The Company received storm assistance from other Southern Company subsidiaries totaling $2.0 million in 2012.

The traditional operating companies, including the Company, and Southern Power may jointly enter into various types of wholesale energy, natural gas, and certain other contracts, either directly or through SCS, as agent. Each participating company

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may be jointly and severally liable for the obligations incurred under these agreements. See Note 7 under "Fuel and Purchased Power Agreements" for additional information.

Regulatory Assets and Liabilities

The Company is subject to the provisions of the Financial Accounting Standards Board in accounting for the effects of rate regulation. Regulatory assets represent probable future revenues associated with certain costs that are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are expected to be credited to customers through the ratemaking process.

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

	2014	2013	Note
	(in thousands)		
Retiree benefit plans – regulatory assets	$169,317	$82,799	(a,g)
Property damage	(61,648)	(60,092)	(i)
Deferred income tax charges	222,599	140,185	(c)
Property tax	27,680	31,206	(d)
Vacation pay	11,172	10,214	(e,g)
Loss on reacquired debt	8,542	9,178	(k)
Plant Daniel Units 3 and 4 regulatory assets	23,013	18,821	(j)
Other regulatory assets	16,270	5,415	(b)
Fuel-hedging (realized and unrealized) losses	46,631	10,340	(f,g)
Asset retirement obligations	10,845	8,918	(c)
Deferred income tax credits	(9,370)	(10,191)	(c)
Other cost of removal obligations	(165,999)	(156,683)	(c)
Kemper IGCC regulatory assets	147,689	75,873	(h)
Mirror CWIP / Kemper regulatory deferral	(270,779)	(90,524)	(h)
Other regulatory liabilities	(4,198)	(8,855)	(b)
Total regulatory assets (liabilities), net	$171,764	$66,604	

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

(a) Recovered and amortized over the average remaining service period which may range up to 14 years. See Note 2 for additional information.

(b) Recorded and recovered (amortized) as approved by the Mississippi PSC.

(c) Asset retirement and removal assets and liabilities and deferred income tax assets are recovered, and removal assets and deferred income tax liabilities are amortized over the related property lives, which may range up to 49 years. Asset retirement and removal assets and liabilities will be settled and trued up following completion of the related activities.

(d) Recovered through the ad valorem tax adjustment clause over a 12-month period beginning in April of the following year. See Note 3 under "Ad Valorem Tax Adjustment" for additional information.

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

(f) Fuel-hedging assets and liabilities are recorded over the life of the underlying hedged purchase contracts, which generally do not exceed four years. Upon final settlement, costs are recovered through the ECM.

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

(h) For additional information, see Note 3 under "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs – Regulatory Assets and Liabilities."

(i) For additional information, see Note 1 under "Provision for Property Damage."

(j)

Deferred and amortized over a 10-year period beginning October 2021, as approved by the Mississippi PSC for the difference between the revenue requirement under the purchase option and the revenue requirement assuming operating lease accounting treatment for the extended term.

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

In the event that a portion of the Company's operations is no longer subject to applicable accounting rules for rate regulation, the Company would be required to write off to income any regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the Company would be required to determine if any impairment to other assets, including plant, exists and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are to be reflected in

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rates. See Note 3 under "Retail Regulatory Matters" and "Integrated Coal Gasification Combined Cycle" for additional information.

Government Grants

In 2010, the DOE, through a cooperative agreement with SCS, agreed to fund $270.0 million of the Kemper IGCC through the DOE Grants funds. Through December 31, 2014, the Company has received grant funds of $245.3 million, used for the construction of the Kemper IGCC, which is reflected in the Company's financial statements as a reduction to the Kemper IGCC capital costs. An additional $25 million is expected to be received for its initial operation. See Note 3 under "Kemper IGCC Schedule and Cost Estimate" for additional information.

Revenues

Energy and other revenues are recognized as services are provided. Wholesale capacity revenues from long-term contracts are recognized at the lesser of the levelized amount or the amount billable under the contract over the respective contract period. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. The Company's retail and wholesale rates include provisions to adjust billings for fluctuations in fuel costs, fuel hedging, the energy component of purchased power costs, and certain other costs. Retail rates also include provisions to adjust billings for fluctuations in costs for ad valorem taxes and certain qualifying environmental costs. Revenues are adjusted for differences between these actual costs and projected amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors. The Company is required to file with the Mississippi PSC for an adjustment to the fuel cost recovery, ad valorem, and environmental factors annually.

The Company serves long-term contracts with rural electric cooperative associations and municipalities located in southeastern Mississippi under cost-based MRA electric tariffs which are subject to regulation by the FERC. The contracts with these wholesale customers represented 21.9% of the Company's total operating revenues in 2014 and are largely subject to rolling 10-year cancellation notices.

The Company has a diversified base of customers. No single customer or industry comprises 10% or more of revenues. For all periods presented, uncollectible accounts averaged less than 1% of revenues.

See Note 3 under "Retail Regulatory Matters" for additional information.

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense generally includes fuel transportation costs and the cost of purchased emissions allowances as they are used. Fuel costs also include gains and/or losses from fuel-hedging programs as approved by the Mississippi PSC.

Income and Other Taxes

The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. ITCs utilized are deferred and amortized to income over the average life of the related property. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of operations.

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

Property, Plant, and Equipment

Property, plant, and equipment is stated at original cost less any regulatory disallowances and impairments. Original cost includes: materials; labor; minor items of property; appropriate administrative and general costs; payroll-related costs such as taxes, pensions, and other benefits; and the interest capitalized and cost of equity funds used during construction for projects where recovery of CWIP is not allowed in rates.

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

	2014	2013
	(in thousands)	
Generation	$2,293,511	$1,475,264
Transmission	664,618	633,903
Distribution	853,835	828,470
General	484,711	439,721
Plant acquisition adjustment	81,412	81,412
Total plant in service	$4,378,087	$3,458,770

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 except for all costs associated with operating and maintaining the Kemper IGCC assets already placed in service and a portion of the railway track maintenance costs, which are charged to fuel stock and recovered through the Company's fuel clause or charged to regulatory assets to be recovered through rates over the life of the assets starting after the Kemper plant is placed in service. In addition, the cost of maintenance, repairs, and replacement of minor items of property for Kemper IGCC assets in service, excluding the lignite mine, are deferred in regulatory assets. See Note 3 under "Integrated Coal Gasification Combined Cycle" for additional information.

Depreciation, Depletion, and Amortization

Depreciation of the original cost of plant in service is provided primarily by using composite straight-line rates, which approximated 3.3% in 2014, 3.4% in 2013, and 3.5% in 2012. Depreciation studies are conducted periodically to update the composite rates. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. Minor items of property included in the original cost of the plant are retired when the related property unit is retired. Depreciation includes an amount for the expected cost of removal of facilities.

In January 2012, the Mississippi PSC issued an order allowing the Company to defer in a regulatory asset the difference between the revenue requirement under the purchase option of Plant Daniel Units 3 and 4 and the revenue requirement assuming operating lease accounting treatment for the extended term. The regulatory asset will be deferred for a 10-year period ending October 2021. At the conclusion of the deferral period, the unamortized deferral balance will be amortized into rates over the remaining life of the units.

The Kemper IGCC will be fueled by locally mined lignite (an abundant, lower heating value coal) from a mine owned by the Company and situated adjacent to the Kemper IGCC. The mine, operated by North American Coal Corporation, started commercial operation in June 2013. Depreciation associated with fixed assets, amortization associated with rolling stock, and depletion associated with minerals and minerals rights is recognized and charged to fuel stock and is expected to be recovered through the Company’s fuel clause. Depreciation associated with in-service Kemper IGCC-related assets has been deferred as a regulatory asset to be recovered over the life of the Kemper IGCC.

Asset Retirement Obligations and Other Costs of Removal

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

The Company has AROs related to various landfill sites, underground storage tanks, deep injection wells, water wells, substation removal, mine reclamation, and asbestos removal. The Company also has identified AROs related to certain transmission and distribution facilities, certain wireless communication towers, and certain structures authorized by the U.S. Army Corps of Engineers. However, liabilities for the removal of these assets have not been recorded because the settlement timing for the AROs related to these assets is indeterminable and, therefore, the fair value of the AROs cannot be reasonably estimated. A liability for these AROs will be recognized when sufficient information becomes available to support a reasonable estimation of the ARO. The Company will continue to recognize in the statements of operations allowed removal costs in accordance with its regulatory treatment. Any differences between costs recognized in accordance with accounting standards related to asset retirement and

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environmental obligations and those reflected in rates are recognized as either a regulatory asset or liability, as ordered by the Mississippi PSC, and are reflected in the balance sheets.
Details of the ARO included in the balance sheets are as follows:

	2014	2013
	(in thousands)	
Balance at beginning of year	$41,910	$42,115
Liabilities settled	(2,529)	(24)
Accretion	1,969	1,840
Cash flow revisions	6,898	(2,021)
Balance at end of year	$48,248	$41,910

The increase in cash flow revisions in 2014 related to the Company's AROs associated with Watson landfill and Greene County asbestos.
On December 19, 2014, the EPA issued the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule), but has not yet published it in the Federal Register. The CCR Rule will regulate the disposal of CCR, including coal ash and gypsum, as non-hazardous solid waste in landfills and surface impoundments at active generating power plants. The ultimate impact of the CCR Rule cannot be determined at this time and will depend on the Company's ongoing review of the CCR Rule, the results of initial and ongoing minimum criteria assessments, and the outcome of legal challenges. The cost and timing of potential ash pond closure and ongoing monitoring activities that may be required in connection with the CCR Rule is also uncertain; however, the Company has developed a preliminary nominal dollar estimate of costs associated with closure and groundwater monitoring of ash ponds in place of approximately $64 million and ongoing post-closure care of approximately $12 million. The Company will record AROs for the estimated closure costs required under the CCR Rule during 2015. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates.
Allowance for Funds Used During Construction
In accordance with regulatory treatment, the Company records AFUDC, which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently from such allowance, AFUDC increases the revenue requirement 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 the calculation of taxable income. The average annual AFUDC rate was 6.91%, 6.89%, and 7.04% for the years ended December 31, 2014, 2013, and 2012, respectively. AFUDC equity was $136.4 million, $121.6 million, and $64.8 million in 2014, 2013, and 2012, respectively.
Impairment of Long-Lived Assets and Intangibles
The Company evaluates long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether an impairment has occurred is based on either a specific regulatory disallowance or an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by either the amount of regulatory disallowance or by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. For assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell in order to determine if an impairment loss is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change. See Note 3 under "Integrated Coal Gasification Combined Cycle – Kemper IGCC Schedule and Cost Estimate" for additional information.
Provision for Property Damage
The Company carries insurance for the cost of certain types of damage to generation plants and general property. However, the Company is self-insured for the cost of storm, fire, and other uninsured casualty damage to its property,

including transmission and distribution facilities. As permitted by the Mississippi PSC and the FERC, the Company accrues for the cost of such damage through an annual expense accrual credited to regulatory liability accounts for the retail and wholesale jurisdictions. The cost of repairing actual damage resulting from such events that individually exceed $50,000 is charged to the reserve. Every three years the Mississippi PSC, MPUS, and the Company will agree on SRR revenue level(s) for the ensuing period, based on historical data, expected exposure, type and amount of insurance coverage, excluding insurance cost, and any other relevant information. The accrual amount and the reserve balance are determined based on the SRR revenue level(s). If a significant change in

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circumstances occurs, then the SRR revenue level can be adjusted more frequently if the Company and the MPUS or the Mississippi PSC deem the change appropriate. The property damage reserve accrual will be the difference between the approved SRR revenues and the SRR revenue requirement, excluding any accrual to the reserve. In addition, SRR allows the Company to set up a regulatory asset, pending review, if the allowable actual retail property damage costs exceed the amount in the retail property damage reserve. In 2014, 2013, and 2012, the Company made retail accruals of $3.3 million, $3.2 million, and $3.5 million, respectively. The Company accrued $0.3 million annually in 2014, 2013, and 2012 for the wholesale jurisdiction. As of December 31, 2014, the property damage reserve balances were $60.7 million and $1.0 million for retail and wholesale, respectively.

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, mining, and generating plant materials. Materials are charged to inventory when purchased and then expensed, capitalized to plant, or charged to fuel stock, as appropriate, at weighted-average cost when utilized.

Fuel Inventory

Fuel inventory includes the average cost of coal, lignite, natural gas, oil, transportation and emissions allowances. Fuel is charged to inventory when purchased, except for the cost of owning and operating the lignite mine related to the Kemper IGCC which is charged to inventory as incurred, and then expensed, at weighted average cost, as used and recovered by the Company through fuel cost recovery rates or capitalized as part of the Kemper IGCC costs if used for testing. The retail rate is approved by the Mississippi PSC and the wholesale rates are approved by the FERC. Emissions allowances granted by the EPA are included in inventory at zero cost.

Financial Instruments

The Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, electricity purchases and sales, and occasionally foreign currency exchange rates. All derivative financial instruments are recognized as either assets or liabilities (included in "Other" or shown separately as "Risk Management Activities") and are measured at fair value. See Note 9 for additional information regarding fair value. Substantially all of the Company's bulk energy purchases and sales contracts that meet the definition of a derivative are excluded from the fair value accounting requirements because they qualify for the "normal" scope exception, and are accounted for under the accrual method. Fuel and interest rate derivative contracts qualify as cash flow hedges of anticipated transactions or are recoverable through the Mississippi PSC approved fuel-hedging program as discussed below result in the deferral of related gains and losses in OCI or regulatory assets and liabilities, respectively, until the hedged transactions occur. Foreign currency exchange rate hedges are designated as fair value hedges. Settled foreign currency exchange hedges are recorded in CWIP. Any ineffectiveness arising from these would be recognized currently in net income; however, the Company has regulatory approval allowing it to defer any ineffectiveness arising from hedging instruments relating to the Kemper IGCC to a regulatory asset. Other derivative contracts that qualify as fair value hedges are marked to market through current period income and are recorded on a net basis in the statements of operations. The amounts related to derivatives on the cash flow statement are classified in the same category as the items being hedged. See Note 10 for additional information regarding derivatives.

The Company does not offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. Additionally, the Company has no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2014.

The Company has an ECM clause which, among other things, allows the Company to utilize financial instruments to hedge its fuel commitments. Changes in the fair value of these financial instruments are recorded as regulatory assets or liabilities. Amounts paid or received as a result of financial settlement of these instruments are classified as fuel expense and are included in the ECM factor applied to customer billings. The Company's jurisdictional wholesale customers have a similar ECM mechanism, which has been approved by the FERC.

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

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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, certain changes in pension and other postretirement benefit plans, and reclassifications for amounts included in net income.

Variable Interest Entities

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

The Company is required to provide financing for all costs associated with the mine development and operation under a contract with Liberty Fuels Company, LLC, a subsidiary of North American Coal Corporation (Liberty Fuels), in conjunction with the construction of the Kemper IGCC. Liberty Fuels qualifies as a VIE for which the Company is the primary beneficiary. For the year ended December 31, 2014, the VIE consolidation resulted in an ARO asset and associated liability in the amounts of $21.0 million and $23.6 million, respectively. For the year ended December 31, 2013, the VIE consolidation resulted in an ARO and an associated liability in the amounts of $21.0 million and $22.7 million, respectively. For the year ended December 31, 2012, the VIE consolidation resulted in an ARO and associated liability in the amounts of $21.0 million and $21.8 million, respectively. See Note 3 under "Integrated Coal Gasification Combined Cycle" for additional information.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). In December 2014, the Company voluntarily contributed $33 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2015. The Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The Company funds its other postretirement trusts to the extent required by the FERC. For the year ending December 31, 2015, no other postretirement trust contributions are expected.

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Actuarial Assumptions
The weighted average rates assumed in the actuarial calculations used to determine both the benefit obligations as of the measurement date and the net periodic costs for the pension and other postretirement benefit plans for the following year are presented below. Net periodic benefit costs were calculated in 2011 for the 2012 plan year using discount rates for the pension plans and the other postretirement benefit plans of 4.98% and 4.87%, respectively, and an annual salary increase of 3.84%.

	2014		2013		2012	
Discount rate:						
Pension plans	4.17	%	5.01	%	4.26	%
Other postretirement benefit plans	4.03		4.85		4.04	
Annual salary increase	3.59		3.59		3.59	
Long-term return on plan assets:						
Pension plans	8.20		8.20		8.20	
Other postretirement benefit plans	7.30		7.04		6.96	

The Company estimates the expected rate of return on pension plan and other postretirement benefit plan assets using a financial model to project the expected return on each current investment portfolio. The analysis projects an expected rate of return on each of seven different asset classes in order to arrive at the expected return on the entire portfolio relying on each trust's target asset allocation and reasonable capital market assumptions. The financial model is based on four key inputs: anticipated returns by asset class (based in part on historical returns), each trust's target asset allocation, an anticipated inflation rate, and the projected impact of a periodic rebalancing of each trust's portfolio.
For purposes of its December 31, 2014 measurement date, the Company adopted new mortality tables for its pension plans and retiree life and medical plans, which reflect increased life expectancies in the U.S. The adoption of new mortality tables increased the projected benefit obligations for the Company's pension plans and other postretirement benefit plans by approximately $30.2 million and $5.2 million, respectively.
An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) was a weighted average medical care cost trend rate. The weighted average medical care cost trend rates used in measuring the APBO as of December 31, 2014 were as follows:

	Initial Cost Trend Rate		Ultimate Cost Trend Rate		Year That Ultimate Rate is Reached
Pre-65	9.00	%	4.50	%	2024
Post-65 medical	6.00		4.50		2024
Post-65 prescription	6.75		4.50		2024

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, 2014 as follows:

	1 Percent Increase	1 Percent Decrease	
	(in thousands)		
Benefit obligation	$6,241	$(5,289	)
Service and interest costs	250	(212	)

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Pension Plans

The total accumulated benefit obligation for the pension plans was $462 million at December 31, 2014 and $370 million at December 31, 2013. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2014 and 2013 were as follows:

	2014	2013
	(in thousands)	
Change in benefit obligation		
Benefit obligation at beginning of year	$409,395	$432,553
Service cost	10,123	11,067
Interest cost	20,093	18,062
Benefits paid	(17,499)	(16,207)
Actuarial (gain) loss	90,735	(36,080)
Balance at end of year	512,847	409,395
Change in plan assets		
Fair value of plan assets at beginning of year	387,403	351,749
Actual return on plan assets	40,051	49,431
Employer contributions	35,526	2,430
Benefits paid	(17,499)	(16,207)
Fair value of plan assets at end of year	445,481	387,403
Accrued liability	$(67,366)	$(21,992)

At December 31, 2014, the projected benefit obligations for the qualified and non-qualified pension plans were $481 million and $32 million, respectively. All pension plan assets are related to the qualified pension plan.

Amounts recognized in the balance sheets at December 31, 2014 and 2013 related to the Company's pension plans consist of the following:

	2014	2013
	(in thousands)	
Prepaid pension costs	$—	$5,698
Other regulatory assets, deferred	150,972	77,572
Other current liabilities	(2,337)	(2,134)
Employee benefit obligations	(65,029)	(25,556)

Presented below are the amounts included in regulatory assets at December 31, 2014 and 2013 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 2015.

	2014	2013	Estimated Amortization in 2015
	(in thousands)		
Prior service cost	$3,030	$4,118	$1,088
Net (gain) loss	147,942	73,454	10,293
Regulatory assets	$150,972	$77,572	

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The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2014 and 2013 are presented in the following table:

	2014	2013
	(in thousands)	
Regulatory assets:		
Beginning balance	$77,572	$146,838
Net (gain) loss	79,425	(58,662)
Reclassification adjustments:		
Amortization of prior service costs	(1,088)	(1,143)
Amortization of net gain (loss)	(4,937)	(9,461)
Total reclassification adjustments	(6,025)	(10,604)
Total change	73,400	(69,266)
Ending balance	$150,972	$77,572

Components of net periodic pension cost were as follows:

	2014	2013	2012
	(in thousands)		
Service cost	$10,123	$11,067	$9,416
Interest cost	20,093	18,062	18,019
Expected return on plan assets	(28,742)	(26,849)	(24,121)
Recognized net (gain) loss	4,937	9,461	4,100
Net amortization	1,088	1,143	1,309
Net periodic pension cost	$7,499	$12,884	$8,723

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, 2014, estimated benefit payments were as follows:

	Benefit Payments
	(in thousands)
2015	$ 23,304
2016	19,551
2017	20,816
2018	21,905
2019	23,337
2020 to 2024	135,320

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Other Postretirement Benefits
Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2014 and 2013 were as follows:

	2014	2013
	(in thousands)	
Change in benefit obligation		
Benefit obligation at beginning of year	$80,940	$91,783
Service cost	1,025	1,151
Interest cost	3,812	3,619
Benefits paid	(4,887)	(4,080)
Actuarial (gain) loss	14,259	(11,959)
Retiree drug subsidy	506	426
Balance at end of year	95,655	80,940
Change in plan assets		
Fair value of plan assets at beginning of year	23,277	21,990
Actual return on plan assets	1,814	2,379
Employer contributions	3,413	2,562
Benefits paid	(4,381)	(3,654)
Fair value of plan assets at end of year	24,123	23,277
Accrued liability	$(71,532)	$(57,663)

Amounts recognized in the balance sheets at December 31, 2014 and 2013 related to the Company's other postretirement benefit plans consist of the following:

	2014	2013
	(in thousands)	
Other regulatory assets, deferred	$18,345	$5,227
Other regulatory liabilities, deferred	(2,011)	(3,111)
Employee benefit obligations	(71,532)	(57,663)

Presented below are the amounts included in net regulatory assets (liabilities) at December 31, 2014 and 2013 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 2015.

	2014	2013	Estimated Amortization in 2015
	(in thousands)		
Prior service cost	$(2,123)	$(2,311)	$(188)
Net (gain) loss	18,457	4,427	778
Net regulatory assets	$16,334	$2,116	

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The changes in the balance of net regulatory assets (liabilities) related to the other postretirement benefit plans for the plan years ended December 31, 2014 and 2013 are presented in the following table:

	2014	2013
	(in thousands)	
Net regulatory assets (liabilities):		
Beginning balance	$2,116	$15,454
Net (gain) loss	14,030	(12,867)
Reclassification adjustments:		
Amortization of prior service costs	188	188
Amortization of net gain (loss)	—	(659)
Total reclassification adjustments	188	(471)
Total change	14,218	(13,338)
Ending balance	$16,334	$2,116

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

	2014	2013	2012
	(in thousands)		
Service cost	$1,025	$1,151	$1,038
Interest cost	3,812	3,619	4,155
Expected return on plan assets	(1,585)	(1,472)	(1,552)
Net amortization	(188)	471	470
Net periodic postretirement benefit cost	$3,064	$3,769	$4,111

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

	Benefit Payments	Subsidy Receipts	Total
	(in thousands)		
2015	$5,387	$(512)	$4,875
2016	5,632	(566)	5,066
2017	5,911	(622)	5,289
2018	6,185	(680)	5,505
2019	6,475	(735)	5,740
2020 to 2024	34,139	(3,744)	30,395

Benefit Plan Assets

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

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The composition of the Company's pension plan and other postretirement benefit plan assets as of December 31, 2014 and 2013, along with the targeted mix of assets for each plan, is presented below:

	Target		2014		2013	
Pension plan assets:						
Domestic equity	26	%	30	%	31	%
International equity	25		23		25	
Fixed income	23		27		23	
Special situations	3		1		1	
Real estate investments	14		14		14	
Private equity	9		5		6	
Total	100	%	100	%	100	%
Other postretirement benefit plan assets:						
Domestic equity	21	%	24	%	25	%
International equity	21		19		20	
Domestic fixed income	37		41		38	
Special situations	3		1		1	
Real estate investments	11		11		11	
Private equity	7		4		5	
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.
- 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, 2014 and 2013. 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

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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.
- 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, 2014 and 2013 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, 2014:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in thousands)			
Assets:				
Domestic equity*	$78,344	$32,366	$—	$110,710
International equity*	49,170	45,313	—	94,483
Fixed income:				
U.S. Treasury, government, and agency bonds	—	32,145	—	32,145
Mortgage- and asset-backed securities	—	8,646	—	8,646
Corporate bonds	—	52,185	—	52,185
Pooled funds	—	23,632	—	23,632
Cash equivalents and other	133	30,327	—	30,460
Real estate investments	13,479	—	51,520	64,999
Private equity	—	—	26,203	26,203
Total	$141,126	$224,614	$77,723	$443,463
Liabilities:				
Derivatives	$(89)	$—	$—	$(89)
Total	$141,037	$224,614	$77,723	$443,374

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

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As of December 31, 2013:	Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1) (in thousands)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
Assets:				
Domestic equity*	$63,558	$37,206	$—	$100,764
International equity*	48,829	45,146	—	93,975
Fixed income:				
U.S. Treasury, government, and agency bonds	—	26,582	—	26,582
Mortgage- and asset-backed securities	—	6,904	—	6,904
Corporate bonds	—	43,420	—	43,420
Pooled funds	—	20,905	—	20,905
Cash equivalents and other	38	9,896	—	9,934
Real estate investments	11,546	—	44,341	55,887
Private equity	—	—	25,316	25,316
Total	$123,971	$190,059	$69,657	$383,687
Liabilities:				
Derivatives	$—	$(115)	$—	$(115)
Total	$123,971	$189,944	$69,657	$383,572

* 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, 2014 and 2013 were as follows:

	2014 Real Estate Investments (in thousands)	Private Equity	2013 Real Estate Investments	Private Equity
Beginning balance	$44,341	$25,316	$37,196	$26,240
Actual return on investments:				
Related to investments held at year end	5,253	3,269	3,385	378
Related to investments sold during the year	1,525	(745)	1,316	2,300
Total return on investments	6,778	2,524	4,701	2,678
Purchases, sales, and settlements	401	(1,637)	2,444	(3,602)
Ending balance	$51,520	$26,203	$44,341	$25,316

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The fair values of other postretirement benefit plan assets as of December 31, 2014 and 2013 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, 2014:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in thousands)			
Assets:				
Domestic equity*	$3,450	$1,425	$—	$4,875
International equity*	2,165	1,997	—	4,162
Fixed income:				
U.S. Treasury, government, and agency bonds	—	5,279	—	5,279
Mortgage- and asset-backed securities	—	380	—	380
Corporate bonds	—	2,301	—	2,301
Pooled funds	—	1,041	—	1,041
Cash equivalents and other	589	1,337	—	1,926
Real estate investments	593	—	2,269	2,862
Private equity	—	—	1,154	1,154
Total	$6,797	$13,760	$3,423	$23,980
Liabilities:				
Derivatives	$(5)	$—	$—	$(5)
Total	$6,792	$13,760	$3,423	$23,975

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

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As of December 31, 2013:	Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in thousands)			
Assets:				
Domestic equity*	$3,089	$1,809	$—	$4,898
International equity*	2,375	2,193	—	4,568
Fixed income:				
U.S. Treasury, government, and agency bonds	—	5,213	—	5,213
Mortgage- and asset-backed securities	—	337	—	337
Corporate bonds	—	2,109	—	2,109
Pooled funds	—	1,016	—	1,016
Cash equivalents and other	1	968	—	969
Real estate investments	560	—	2,156	2,716
Private equity	—	—	1,231	1,231
Total	$6,025	$13,645	$3,387	$23,057
Liabilities:				
Derivatives	$—	$(5)	$—	$(5)
Total	$6,025	$13,640	$3,387	$23,052

* 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, 2014 and 2013 were as follows:

	2014 Real Estate Investments	2014 Private Equity	2013 Real Estate Investments	2013 Private Equity
	(in thousands)			
Beginning balance	$2,156	$1,231	$1,865	$1,293
Actual return on investments:				
Related to investments held at year end	28	28	158	18
Related to investments sold during the year	67	(33)	64	110
Total return on investments	95	(5)	222	128
Purchases, sales, and settlements	18	(72)	69	(190)
Ending balance	$2,269	$1,154	$2,156	$1,231

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides an 85% matching contribution on up to 6% of an employee's base salary. Total matching contributions made to the plan for 2014, 2013, and 2012 were $4.6 million, $4.1 million, and $3.9 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including

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property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by CO_2 and other emissions, CCR, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements.

Environmental Matters

New Source Review Actions

As part of a nationwide enforcement initiative against the electric utility industry which began in 1999, the EPA brought civil enforcement actions in federal district court against Alabama Power alleging violations of the New Source Review (NSR) provisions of the Clean Air Act at certain coal-fired electric generating units, including a unit co-owned by the Company. These civil actions seek penalties and injunctive relief, including orders requiring installation of the best available control technologies at the affected units. These actions were filed concurrently with the issuance of notices of violation to the Company with respect to the Company's Plant Watson. The case against Alabama Power (including claims involving a unit co-owned by the Company) 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. In September 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.

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

Environmental Remediation

The Company must comply with environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company may also incur substantial costs to clean up properties. The Company has authority from the Mississippi PSC to recover approved environmental compliance costs through regulatory mechanisms.

In 2003, the Company and numerous other entities were designated by the Texas Commission on Environmental Quality (TCEQ) as potentially responsible parties at a site that was owned by an electric transformer company that handled the Company's transformers. The TCEQ approved the final site remediation plan in December 2013 and, on March 28, 2014, the impacted utilities, including the Company, agreed to commence remediation actions on the site. The Company's environmental remediation liability is $0.5 million as of December 31, 2014 and is expected to be recovered through the ECO Plan.

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

FERC Matters

In 2012, the Company entered into a settlement agreement with its wholesale customers with respect to the Company's request for revised rates under the wholesale cost-based electric tariff. The settlement agreement provided that base rates under the cost-based electric tariff increase by approximately $22.6 million over a 12-month period with revised rates effective April 1, 2012. A significant portion of the difference between the requested base rate increase and the agreed upon rate increase was due to a change in the recovery methodology for the return on the Kemper IGCC CWIP. Under the settlement agreement, a portion of CWIP will continue to accrue AFUDC. The tariff customers specifically agreed to the same regulatory treatment for tariff ratemaking as the treatment approved for retail ratemaking by the Mississippi PSC with respect to (i) the accounting for Kemper IGCC-related costs that cannot be capitalized, (ii) the accounting for the lease termination and purchase of Plant Daniel Units 3 and 4, and (iii) the establishment of a regulatory asset for certain potential plant retirement costs.

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Also in 2012, the FERC approved a motion to place interim rates into effect beginning in May 2012. Later in 2012, the Company, with its wholesale customers, filed a final settlement agreement with the FERC. In May 2013, the Company received an order from the FERC accepting the settlement agreement.

In April 2013, the Company reached a settlement agreement with its wholesale customers and filed a request with the FERC for an additional increase in the MRA cost-based electric tariff, which was accepted by the FERC in May 2013. The 2013 settlement agreement provided that base rates under the MRA cost-based electric tariff will increase by approximately $24.2 million annually, effective April 1, 2013.

On March 31, 2014, the Company reached a settlement agreement with its wholesale customers and filed a request with the FERC for an increase in the MRA cost-based electric tariff. The settlement agreement, accepted by the FERC on May 20, 2014, provides that base rates under the MRA cost-based electric tariff will increase approximately $10.1 million annually, with revised rates effective for services rendered beginning May 1, 2014.

Retail Regulatory Matters

General

In 2012, the Mississippi PSC issued an order for the purpose of investigating and reviewing, for informational purposes only, the ROE formulas used by the Company and all other regulated electric utilities in Mississippi. In March 2013, the MPUS filed with the Mississippi PSC its report on the ROE formulas used by the Company and all other regulated electric utilities in Mississippi. The ultimate outcome of this matter cannot be determined at this time.

Energy Efficiency

In July 2013, the Mississippi PSC approved an energy efficiency and conservation rule requiring electric and gas utilities in Mississippi serving more than 25,000 customers to implement energy efficiency programs and standards. Quick Start Plans, which include a portfolio of energy efficiency programs that are intended to provide benefits to a majority of customers, were required to be filed within six months of the order and will be in effect for two to three years. An annual report addressing the performance of all energy efficiency programs is required.

On June 3, 2014, the Mississippi PSC approved the Company's 2014 Energy Efficiency Quick Start Plan filing, which includes a portfolio of energy efficiency programs. On October 20, 2014, the Company filed a revised compliance filing, which proposed an increase of $6.7 million in retail revenues for the period December 2014 through December 2015. The Mississippi PSC approved the revised filing on November 4, 2014.

Performance Evaluation Plan

The Company’s retail base rates are set under the PEP, a rate plan approved by the Mississippi PSC. Two filings are made for each calendar year: the PEP projected filing, which is typically filed prior to the beginning of the year based on projected revenue requirement, and the PEP lookback filing, which is filed after the year and allows for review of the actual revenue requirement compared to the projected filing. PEP was designed with the objective to reduce the impact of rate changes on the customer and provide incentives for the Company to keep customer prices low and customer satisfaction and reliability high. PEP is a mechanism for rate adjustments based on three indicators: price, customer satisfaction, and service reliability.

In 2011, the Company submitted its annual PEP lookback filing for 2010, which recommended no surcharge or refund. Later in 2011, the Company received a letter from the MPUS disputing certain items in the 2010 PEP lookback filing. In 2012, the Mississippi PSC issued an order canceling the Company's PEP lookback filing for 2011. In May 2013, the MPUS contested the Company's PEP lookback filing for 2012, which indicated a refund due to customers of $4.7 million. Unresolved matters related to certain costs included in the 2010 PEP lookback filing, which are currently under review, also impact the 2012 PEP lookback filing.

In March 2013, the Mississippi PSC approved the projected PEP filing for 2013, which resulted in a rate increase of 1.9%, or $15.3 million, annually, effective March 19, 2013. The Company may be entitled to $3.3 million in additional revenues related to 2013 as a result of the late implementation of the 2013 PEP rate increase.

On March 18, 2014, the Company submitted its annual PEP lookback filing for 2013, which indicated no surcharge or refund. On March 31, 2014, the Mississippi PSC suspended the filing to allow more time for review.

On June 3, 2014, the Mississippi PSC issued an order for the purpose of investigating and reviewing the adoption of a uniform formula rate plan for the Company and other regulated electric utilities in Mississippi.
The ultimate outcome of these matters cannot be determined at this time.

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Environmental Compliance Overview Plan
In 2012, the Mississippi PSC approved the Company's request for a CPCN to construct scrubbers on Plant Daniel Units 1 and 2, which are scheduled to be placed in service in September and November 2015, respectively. These units are jointly owned by the Company and Gulf Power, with 50% ownership each. The estimated total cost of the project is approximately $660 million, with the Company's portion being $330 million, excluding AFUDC. The Company's portion of the cost is expected to be recovered through the ECO Plan following the scheduled completion of the project. As of December 31, 2014, total project expenditures were $518.2 million, of which the Company's portion was $263.4 million, excluding AFUDC of $19.2 million.
In August 2013, the Mississippi PSC approved the Company’s 2013 ECO Plan filing which proposed no change in rates.
On August 1, 2014, the Company entered into a settlement agreement with the Sierra Club (Sierra Club Settlement Agreement) that, among other things, requires the Sierra Club to dismiss or withdraw all pending legal and regulatory challenges to the issuance of the CPCN to construct scrubbers on Plant Daniel Units 1 and 2. In addition, and consistent with the Company's ongoing evaluation of recent environmental rules and regulations, the Company agreed to retire, repower with natural gas, or convert to an alternative non-fossil fuel source Plant Sweatt Units 1 and 2 (80 MWs) no later than December 2018. The Company also agreed that it would cease burning coal and other solid fuel at Plant Watson Units 4 and 5 (750 MWs) and begin operating those units solely on natural gas no later than April 2015, and cease burning coal and other solid fuel at Plant Greene County Units 1 and 2 (200 MWs) and begin operating those units solely on natural gas no later than April 2016. On August 28, 2014, the Chancery Court of Harrison County, Mississippi dismissed the Sierra Club's appeal related to the CPCN to construct scrubbers on Plant Daniel Units 1 and 2.
In accordance with a 2011 accounting order from the Mississippi PSC, the Company has the authority to defer in a regulatory asset for future recovery all plant retirement- or partial retirement-related costs resulting from environmental regulations. This request was made to minimize the potential rate impact to customers arising from pending and final environmental regulations which may require the premature retirement of some generating units. As of December 31, 2014, $5.6 million of Plant Greene County costs and $2.0 million of costs related to Plant Watson have been reclassified as a regulatory asset. These costs are expected to be recovered through the ECO plan and other existing cost recovery mechanisms. Additional costs associated with the remaining net book value of coal-related equipment will be reclassified to a regulatory asset at the time of retirement for Plants Watson and Greene County in 2015 and 2016, respectively. Approved regulatory asset costs will be amortized over a period to be determined by the Mississippi PSC. As a result, these decisions are not expected to have a material impact on the Company's financial statements. See "Other Matters – Sierra Club Settlement Agreement" herein for additional information.
The ultimate outcome of these matters cannot be determined at this time.
Fuel Cost Recovery
The Company establishes, annually, a retail fuel cost recovery factor that is approved by the Mississippi PSC. The Company is required to file for an adjustment to the retail fuel cost recovery factor annually; the most recent filing occurred on November 17, 2014. On January 13, 2015, the Mississippi PSC approved the 2015 retail fuel cost recovery factor, effective January 21, 2015. The retail fuel cost recovery factor will result in an annual increase of approximately $7.9 million. At December 31, 2014, the amount of under-recovered retail fuel costs included in the balance sheets was $2.5 million compared to a $14.5 million over-recovered balance at December 31, 2013.
The Company also has a wholesale MRA and a Market Based (MB) fuel cost recovery factor. Effective January 1, 2015, the wholesale MRA fuel rate decreased resulting in an annual decrease of $1.1 million. Effective February 1, 2015, the wholesale MB fuel rate decreased, resulting in an annual decrease of $0.1 million. At December 31, 2014, the amount of over-recovered wholesale MRA fuel costs included in the balance sheets was $0.2 million compared to an over-recovered balance of $7.3 million at December 31, 2013. At December 31, 2014, the amount of over-recovered wholesale MB fuel costs included in the balance sheets was immaterial compared to an over-recovered

balance of $0.3 million at December 31, 2013. In addition, at December 31, 2014, the amount of over-recovered MRA emissions allowance cost included in the balance sheets was $0.3 million compared to a $3.8 million under-recovered balance at December 31, 2013. The Company's operating revenues are adjusted for differences in actual recoverable fuel cost and amounts billed in accordance with the currently approved cost recovery rate. Accordingly, changes in the billing factor should have no significant effect on the Company's revenues or net income, but will affect cash flow.

Ad Valorem Tax Adjustment

The Company establishes, annually, an ad valorem tax adjustment factor that is approved by the Mississippi PSC to collect the ad valorem taxes paid by the Company. On May 6, 2014, the Mississippi PSC approved the Company's annual ad valorem tax adjustment factor filing for 2014, in which the Company requested an annual rate increase of 0.38%, or $3.6 million in annual retail revenues, primarily due to an increase in property tax rates.

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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. In the 2015 Mississippi Supreme Court (Court) decision, the Court declined to rule on the constitutionality of the Baseload Act. See "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs" and " – 2015 Mississippi Supreme Court Decision" herein for additional information.

Integrated Coal Gasification Combined Cycle

Kemper IGCC Overview

Construction of the Kemper IGCC is nearing completion and start-up activities will continue until the Kemper IGCC is placed in service. The Kemper IGCC will utilize an IGCC technology with an output capacity of 582 MWs. The Kemper IGCC will be fueled by locally mined lignite (an abundant, lower heating value coal) from a mine owned by the Company and situated adjacent to the Kemper IGCC. The mine, operated by North American Coal Corporation, started commercial operation in June 2013. In connection with the Kemper IGCC, the Company constructed and plans to operate approximately 61 miles of CO_2 pipeline infrastructure for the planned transport of captured CO_2 for use in enhanced oil recovery.

Kemper IGCC Schedule and Cost Estimate

In 2012, the Mississippi PSC issued the 2012 MPSC CPCN Order, a detailed order confirming the CPCN originally approved by the Mississippi PSC in 2010 authorizing the acquisition, construction, and operation of the Kemper IGCC.

The certificated cost estimate of the Kemper IGCC included in the 2012 MPSC CPCN Order was \$2.4 billion, net of \$245.3 million of DOE Grants and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, and AFUDC related to the Kemper IGCC. The 2012 MPSC CPCN Order approved a construction cost cap of up to \$2.88 billion, with recovery of prudently-incurred costs subject to approval by the Mississippi PSC.

The Kemper IGCC was originally projected to be placed in service in May 2014. The Company placed the combined cycle and the associated common facilities portion of the Kemper IGCC in service on natural gas on August 9, 2014 and continues to focus on completing the remainder of the Kemper IGCC, including the gasifier and the gas clean-up facilities, for which the in-service date is currently expected to occur in the first half of 2016.

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Recovery of the Kemper IGCC 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 the Company demonstrates that the purpose and effect of the construction cost increase is to produce efficiencies that will result in a neutral or favorable effect on customers relative to the original proposal for the CPCN) (Cost Cap Exceptions) and costs subject to the cost cap remain subject to review and approval by the Mississippi PSC. The Company's Kemper IGCC 2010 project estimate, current cost estimate (which includes the impacts of the Court's decision), and actual costs incurred as of December 31, 2014, as adjusted for the Court's decision, are as follows:

Cost Category	2010 Project Estimate[f]	Current Estimate	Actual Costs at 12/31/2014
	(in billions)		
Plant Subject to Cost Cap[a]	$2.40	$4.93	$4.23
Lignite Mine and Equipment	0.21	0.23	0.23
CO_2 Pipeline Facilities	0.14	0.11	0.10
AFUDC[b][c]	0.17	0.63	0.45
Combined Cycle and Related Assets Placed in Service – Incremental[d]	—	0.02	0.00
General Exceptions	0.05	0.10	0.07
Deferred Costs[c][e]	—	0.18	0.12
Total Kemper IGCC[a][c]	$2.97	$6.20	$5.20

(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. The Current Estimate and Actual Costs include non-incremental operating and maintenance costs related to the combined cycle and associated common facilities placed in service on August 9, 2014 that are subject to the $2.88 billion cost cap and excludes post-in-service costs for the lignite mine. See "Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order" for additional information.

(b) The Company's original estimate included recovery of financing costs during construction rather than the accrual of AFUDC. This approach was not approved by the Mississippi PSC in 2012 as described in "Rate Recovery of Kemper IGCC Costs."

(c) Amounts in the Current Estimate reflect estimated costs through March 31, 2016.

(d) Incremental operating and maintenance costs related to the combined cycle and associated common facilities placed in service on August 9, 2014, net of costs related to energy sales. See "Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order" for additional information.

(e) The 2012 MPSC CPCN Order approved deferral of non-capital Kemper IGCC-related costs during construction as described in "Rate Recovery of Kemper IGCC Costs – Regulatory Assets and Liabilities."

(f) The 2010 Project Estimate is the certificated cost estimate adjusted to include the certificated estimate for the CO_2 pipeline facilities which was approved in 2011 by the Mississippi PSC.

Of the total costs, including post-in-service costs for the lignite mine, incurred as of December 31, 2014, $3.04 billion was included in property, plant, and equipment (which is net of the DOE Grants and estimated probable losses of $2.05 billion), $1.8 million in other property and investments, $44.7 million in fossil fuel stock, $32.5 million in materials and supplies, $147.7 million in other regulatory assets, $11.6 million in other deferred charges and assets, and $23.6 million in AROs in the balance sheet, with $1.1 million previously expensed.

The Company does not intend to seek any rate recovery or joint owner contributions for any costs related to the construction of the Kemper IGCC that exceed the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions. The Company recorded pre-tax charges to income for revisions to the cost estimate of $868.0 million ($536.0 million after tax), $1.10 billion ($680.5 million after tax), and $78.0 million ($48.2 million after tax) in 2014, 2013 and 2012, respectively. The increases to the cost estimate in 2014 primarily reflected costs related to extension of the project's schedule to ensure the required time for start-up activities and operational readiness, completion of construction, additional resources during start-up, and ongoing construction support during start-up and commissioning activities. The current estimate includes costs through March 31, 2016. Any further extension of the in-service date is currently estimated to result in additional base costs of approximately $25 million to $30 million per month, which includes maintaining necessary levels of start-up labor, materials, and fuel, as well as operational resources required to execute start-up and commissioning activities. Any further extension of the in-service date with respect to the Kemper IGCC would also increase costs for the Cost Cap Exceptions, which are not subject to the $2.88 billion cost cap established by the Mississippi PSC. These costs include AFUDC, which is currently estimated to total approximately $13 million per month, as well as carrying costs and operating expenses on Kemper IGCC assets placed in service and consulting and legal fees, which are being deferred as regulatory assets and are estimated to total approximately $7 million per month.

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

Rate Recovery of Kemper IGCC Costs

See "FERC Matters" for additional information regarding the Company's MRA cost-based tariff relating to recovery of a portion of the Kemper IGCC costs from the Company's wholesale customers. Rate recovery of the retail portion of the Kemper IGCC is subject to the jurisdiction of the Mississippi PSC. See Note 3 under "Retail Regulatory Matters – Baseload Act" for additional information. See "Investment Tax Credits and Bonus Depreciation" and "Section 174 Research and Experimental Deduction" herein for additional tax information related to the Kemper IGCC.

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 the Company's recovery of financing costs during the course of construction of the Kemper IGCC and the Company's recovery of costs following the date the Kemper IGCC is placed in service. 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 the Company's petition for the CPCN. The Company expects the Mississippi PSC to apply operational parameters in connection with the evaluation of the Rate Mitigation Plan (defined below) and other related proceedings during the operation of the Kemper IGCC. To the extent the Mississippi PSC determines the Kemper IGCC does not meet the operational parameters ultimately adopted by the Mississippi PSC or the Company incurs additional costs to satisfy such parameters, there could be a material adverse impact on the Company's financial statements.

2013 Settlement Agreement

In January 2013, the Company entered into a settlement agreement with the Mississippi PSC that, among other things, established the process for resolving matters regarding cost recovery related to the Kemper IGCC (2013 Settlement Agreement). Under the 2013 Settlement Agreement, the Company 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 2013 Settlement Agreement also allowed the Company to secure alternate financing for costs not otherwise recovered in any Mississippi PSC rate proceedings contemplated by the 2013 Settlement Agreement. The Court found the 2013 Settlement Agreement unenforceable due to a lack of public notice for the related proceedings. See "2015 Mississippi Supreme Court Decision" below for additional information.

Legislation to authorize a multi-year rate plan and legislation to provide for alternate financing through securitization of up to $1.0 billion of prudently-incurred costs was enacted into law in February 2013. The Company's intent under the 2013 Settlement Agreement was 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, which include carrying costs from the estimated in-service date until securitization is finalized and other costs not included in the Rate Mitigation Plan as approved by the Mississippi PSC.

The Court's decision did not impact the Company's ability to utilize alternate financing through securitization, the 2012 MPSC CPCN Order, or the February 2013 legislation. See "2015 Mississippi Supreme Court Decision" below for additional information.

2013 MPSC Rate Order

Consistent with the terms of the 2013 Settlement Agreement, in March 2013, the Mississippi PSC issued the 2013 MPSC Rate Order approving retail rate increases of 15% effective March 19, 2013 and 3% effective January 1, 2014, which collectively were designed to collect $156 million annually beginning in 2014. For the period from March 2013 through December 31, 2014,

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$257.2 million had been collected primarily to be used to mitigate customer rate impacts after the Kemper IGCC is placed in service.

Because the 2013 MPSC Rate Order did not provide for the inclusion of CWIP in rate base as permitted by the Baseload Act, the Company continues to record AFUDC on the Kemper IGCC through the in-service date. The Company 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. The Company will continue to record AFUDC and collect and defer the approved rates through the in-service date until directed to do otherwise by the Mississippi PSC.

On August 18, 2014, the Company provided an analysis of the costs and benefits of placing the combined cycle and the associated common facilities portion of the Kemper IGCC in service, including the expected accounting treatment. The Company's analysis requested, among other things, confirmation of the Company's accounting treatment by the Mississippi PSC of the continued collection of rates as prescribed by the 2013 MPSC Rate Order, with the current recognition as revenue of the related equity return on all assets placed in service and the deferral of all remaining rate collections under the 2013 MPSC Rate Order to a regulatory liability account. See "2015 Mississippi Supreme Court Decision" for additional information regarding the decision of the Court which would discontinue the collection of, and require the refund of, all amounts previously collected under the 2013 MPSC Rate Order.

In addition, the Company's August 18, 2014 filing with the Mississippi PSC requested confirmation of the Company's accounting treatment by the Mississippi PSC of the continued accrual of AFUDC through the in-service date of the remainder of the Kemper IGCC and the deferral of operating costs for the combined cycle as regulatory assets. Under the Company's proposal, non-incremental costs that would have been incurred whether or not the combined cycle was placed in service would be included in a regulatory asset and would continue to be subject to the $2.88 billion cost cap. Additionally, incremental costs that would not have been incurred if the combined cycle had not gone into service would be included in a regulatory asset and would not be subject to the cost cap because these costs are incurred to support operation of the combined cycle. All energy revenues associated with the combined cycle variable operating and maintenance expenses would be credited to this regulatory asset. See "Regulatory Assets and Liabilities" for additional information. Any action by the Mississippi PSC that is inconsistent with the treatment requested by the Company could have a material impact on the results of operations, financial condition, and liquidity of the Company.

2015 Mississippi Supreme Court Decision

On February 12, 2015, the Court issued its decision in the legal challenge to the 2013 MPSC Rate Order filed by Thomas A. Blanton. The Court reversed the 2013 MPSC Rate Order based on, among other things, its findings that (1) the Mirror CWIP rate treatment was not provided for under the Baseload Act and (2) the Mississippi PSC should have determined the prudence of Kemper IGCC costs before approving rate recovery through the 2013 MPSC Rate Order. The Court also found the 2013 Settlement Agreement unenforceable due to a lack of public notice for the related proceedings. The Court's ruling remands the matter to the Mississippi PSC to (1) fix by order the rates that were in existence prior to the 2013 MPSC Rate Order, (2) fix no rate increases until the Mississippi PSC is in compliance with the Court's ruling, and (3) enter an order refunding amounts collected under the 2013 MPSC Rate Order. Through December 31, 2014, the Company had collected $257.2 million through rates under the 2013 MPSC Rate Order. Any required refunds would also include carrying costs. The Court's decision will become legally effective upon the issuance of a mandate to the Mississippi PSC. Absent specific instruction from the Court, the Mississippi PSC will determine the method and timing of the refund. The Company is reviewing the Court's decision and expects to file a motion for rehearing which would stay the Court's mandate until either the case is reheard and decided or seven days after the Court issues its order denying the Company's request for rehearing. The Company is also evaluating its regulatory options.

Rate Mitigation Plan

In March 2013, the Company, in compliance with the 2013 MPSC Rate Order, filed a revision to the proposed rate recovery plan with the Mississippi PSC for the Kemper IGCC for cost recovery through 2020 (Rate Mitigation Plan), which is still under review by the Mississippi PSC. The revenue requirements set forth in the Rate Mitigation Plan assume the sale of a 15% undivided interest in the Kemper IGCC to SMEPA and utilization of bonus depreciation, which currently requires that the related long-term asset be placed in service in 2015. In the Rate Mitigation Plan, the Company 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 in March 2013, was integral to the Rate Mitigation 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 Rate Mitigation Plan, the Company proposed annual rate recovery to remain the same from 2014

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through 2020, with the proposed revenue requirement approximating the forecasted cost of service for the period 2014 through 2020. Under the Company's proposal, to the extent the actual annual cost of service differs from the approved forecast for certain items, 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 2020, the Mississippi PSC would review the amount and, if approved, determine the appropriate method and period of disposition. See "Regulatory Assets and Liabilities" and "Investment Tax Credits and Bonus Depreciation" for additional information.

To the extent that refunds of amounts collected under the 2013 MPSC Rate Order are required on a schedule different from the amortization schedule proposed in the Rate Mitigation Plan, the customer billing impacts proposed under the Rate Mitigation Plan would no longer be viable. See "2015 Mississippi Supreme Court Decision" above for additional information.

In the event that the Mirror CWIP regulatory liability is refunded to customers prior to the in-service date of the Kemper IGCC and is, therefore, not available to mitigate rate impacts under the Rate Mitigation Plan, the Mississippi PSC does not approve a refund schedule that facilitates rate mitigation, or the Company withdraws the Rate Mitigation Plan, the Company would seek rate recovery through alternate means, which could include a traditional rate case.

In addition to current estimated costs at December 31, 2014 of $6.20 billion, the Company anticipates that it will incur additional costs after the Kemper IGCC in-service date until the Kemper IGCC cost recovery approach is finalized. These costs include, but are not limited to, regulatory costs and additional carrying costs which could be material. Recovery of these costs would be subject to approval by the Mississippi PSC.

Prudence Reviews

The Mississippi PSC's review of Kemper IGCC costs is ongoing. On August 5, 2014, the Mississippi PSC ordered that a consolidated prudence determination of all Kemper IGCC costs be completed after the entire project has been placed in service and has demonstrated availability for a reasonable period of time as determined by the Mississippi PSC and the MPUS. The Mississippi PSC has encouraged the parties to work in good faith to settle contested issues and the Company is working to reach a mutually acceptable resolution. As a result of the Court's decision, the Company intends to request that the Mississippi PSC reconsider its prudence review schedule. See "2015 Mississippi Supreme Court Decision" for additional information.

Regulatory Assets and Liabilities

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

On August 18, 2014, the Company requested confirmation by the Mississippi PSC of the Company's authority to defer all operating expenses associated with the operation of the combined cycle subject to review of such costs by the Mississippi PSC. In addition, the Company is authorized to accrue carrying costs on the unamortized balance of such regulatory assets at a rate and in a manner to be determined by the Mississippi PSC in future cost recovery mechanism proceedings. As of December 31, 2014, the regulatory asset balance associated with the Kemper IGCC was $147.7 million. The projected balance at March 31, 2016 is estimated to total approximately $269.8 million. The amortization period of 40 years proposed by the Company for any such costs approved for recovery remains subject to approval by the Mississippi PSC.

The 2013 MPSC Rate Order approved retail rate increases of 15% effective March 19, 2013 and 3% effective January 1, 2014, which collectively were designed to collect $156 million annually beginning in 2014. On February 12, 2015, the Court ordered the Mississippi PSC to refund Mirror CWIP and to fix by order the rates that were in existence prior to the 2013 MPSC Rate Order. The Company is deferring the collections under the approved rates in the Mirror CWIP regulatory liability until otherwise directed by the Mississippi PSC. The Company is also accruing carrying costs on the unamortized balance of the Mirror CWIP regulatory liability for the benefit of retail customers. As of December 31, 2014, the balance of the Mirror CWIP regulatory liability, including carrying costs, was $270.8 million.

See "2015 Mississippi Supreme Court Decision" for additional information.

See Note 1 under "Regulatory Assets and Liabilities" for additional information.

Lignite Mine and CO_2 Pipeline Facilities

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

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In 2010, the Company executed a 40-year management fee contract with Liberty Fuels Company, LLC (Liberty Fuels), a wholly-owned subsidiary of The North American Coal Corporation, which developed, constructed, and is operating and managing the mining operations. The contract with Liberty Fuels is effective through the end of the mine reclamation. As the mining permit holder, Liberty Fuels has a legal obligation to perform mine reclamation and the Company has a contractual obligation to fund all reclamation activities. In addition to the obligation to fund the reclamation activities, the Company currently provides working capital support to Liberty Fuels through cash advances for capital purchases, payroll, and other operating expenses. See Note 1 under "Asset Retirement Obligations and Other Costs of Removal" and "Variable Interest Entities" for additional information.

In addition, the Company has constructed and will operate the CO_2 pipeline for the planned transport of captured CO_2 for use in enhanced oil recovery. The Company has entered into agreements with Denbury Onshore (Denbury), a subsidiary of Denbury Resources Inc., and Treetop Midstream Services, LLC (Treetop), an affiliate of Tellus Operating Group, LLC and a subsidiary of Tengrys, LLC, pursuant to which Denbury will purchase 70% of the CO_2 captured from the Kemper IGCC and Treetop will purchase 30% of the CO_2 captured from the Kemper IGCC. The agreements with Denbury and Treetop provide termination rights in the event that the Company does not satisfy its contractual obligation with respect to deliveries of captured CO_2 by May 11, 2015. While the Company has received no indication from either Denbury or Treetop of their intent to terminate their respective agreements, any termination could result in a material reduction in future chemical product sales revenues and could have a material financial impact on the Company to the extent the Company is not able to enter into other similar contractual arrangements. The ultimate outcome of these matters cannot be determined at this time.

Proposed Sale of Undivided Interest to SMEPA

In 2010, the Company and SMEPA entered into an APA whereby SMEPA agreed to purchase a 17.5% undivided interest in the Kemper IGCC. In 2012, the Mississippi PSC approved the sale and transfer of the 17.5% undivided interest in the Kemper IGCC to SMEPA. Later in 2012, the Company and SMEPA signed an amendment to the APA whereby SMEPA reduced its purchase commitment percentage from a 17.5% to a 15% undivided interest in the Kemper IGCC. In March 2013, the Company and SMEPA signed an amendment to the APA whereby the Company and SMEPA agreed to amend the power supply agreement entered into by the parties in 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 2011 power supply agreement were $16.7 million in 2014. In December 2013, the Company and SMEPA agreed to extend SMEPA's option to purchase through December 31, 2014.

By letter agreement dated October 6, 2014, the Company and SMEPA agreed in principle on certain issues related to SMEPA's proposed purchase of a 15% undivided interest in the Kemper IGCC. The letter agreement contemplated certain amendments to the APA, which the parties anticipated to be incorporated into the APA on or before December 31, 2014. The parties agreed to further amend the APA as follows: (1) the Company agreed to cap at $2.88 billion the portion of the purchase price payable for development and construction costs, net of the Cost Cap Exceptions, title insurance reimbursement, and AFUDC and/or carrying costs through the Closing Commitment Date (defined below); (2) SMEPA agreed to close the purchase within 180 days after the date of the execution of the amended APA or before the Kemper IGCC in-service date, whichever occurs first (Closing Commitment Date), subject only to satisfaction of certain conditions; and (3) AFUDC and/or carrying costs will continue to be accrued on the capped development and construction costs, the Cost Cap Exceptions, and any operating costs, net of revenues until the amended APA is executed by both parties, and thereafter AFUDC and/or carrying costs and payment of interest on SMEPA's deposited money will be suspended and waived provided closing occurs by the Closing Commitment Date. The letter agreement also provided for certain post-closing adjustments to address any differences between the actual and the estimated amounts of post-in-service date costs (both expenses and capital) and revenue credits for those portions of the Kemper IGCC previously placed in service.

By letter dated December 18, 2014, SMEPA notified the Company that SMEPA decided not to extend the estimated closing date in the APA or revise the APA to include the contemplated amendments; however, both parties agree that the APA will remain in effect until closing or until either party gives notice of termination.

The closing of this transaction is also conditioned upon execution of a joint ownership and operating agreement, the absence of material adverse effects, receipt of all construction permits, and appropriate regulatory approvals, as well as SMEPA's receipt of Rural Utilities Service (RUS) funding. In 2012, SMEPA received a conditional loan commitment from RUS for the purchase.

In 2012, on January 2, 2014, and on October 9, 2014, the Company received $150 million, $75 million, and $50 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, the Company would be required to refund the deposits upon the termination of the APA or within 15 days of a request by SMEPA for a full or partial refund. Given the interest-bearing nature of

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the deposits and SMEPA's ability to request a refund, the deposits have been presented as a current liability in the balance sheet and as financing proceeds in the statement of cash flow. In July 2013, Southern Company entered into an agreement with SMEPA under which Southern Company has agreed to guarantee the obligations of the Company with respect to any required refund of the deposits.

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

Investment Tax Credits and Bonus Depreciation

The IRS allocated $279.0 million (Phase II) of Internal Revenue Code Section 48A tax credits to the Company in connection with the Kemper IGCC. Through December 31, 2014, the Company had recorded tax benefits totaling $276.4 million for the Phase II credits, of which approximately $210.0 million had been utilized through that date. These credits 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. The Company currently expects to place the Kemper IGCC in service in the first half of 2016. In addition, a portion of the Phase II tax credits will be subject to recapture upon completion of SMEPA's proposed purchase of an undivided interest in the Kemper IGCC as described above.

On December 19, 2014, the Tax Increase Prevention Act of 2014 (TIPA) was signed into law. The TIPA retroactively extended several tax credits through 2014 and extended 50% bonus depreciation for property placed in service in 2014 (and for certain long-term production-period projects to be placed in service in 2015). The extension of 50% bonus depreciation had a positive impact on the Company's cash flows and combined with bonus depreciation allowed in 2014 under the American Taxpayer Relief Act of 2012, resulted in approximately $130 million of positive cash flows related to the combined cycle and associated common facilities portion of the Kemper IGCC for the 2014 tax year. The estimated cash flow benefit of bonus depreciation related to TIPA is expected to be approximately $45 million to $50 million for the 2015 tax year.

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

Section 174 Research and Experimental Deduction

Southern Company, on behalf of the Company, reduced tax payments for 2014 and included in its 2013 consolidated federal income tax return deductions for research and experimental (R&E) expenditures related to the Kemper IGCC. Due to the uncertainty related to this tax position, the Company recorded an unrecognized tax benefit of approximately $160 million as of December 31, 2014. See Note 5 under "Unrecognized Tax Benefits" for additional information.

Other Matters

Sierra Club Settlement Agreement

On August 1, 2014, the Company entered into the Sierra Club Settlement Agreement that, among other things, requires the Sierra Club to dismiss or withdraw all pending legal and regulatory challenges of the Kemper IGCC and the scrubber project at Plant Daniel Units 1 and 2. In addition, the Sierra Club agreed to refrain from initiating, intervening in, and/or challenging certain legal and regulatory proceedings for the Kemper IGCC, including, but not limited to, the prudence review, and Plant Daniel for a period of three years from the date of the Sierra Club Settlement Agreement. On August 4, 2014, the Sierra Club filed all of the required motions necessary to dismiss or withdraw all appeals associated with certification of the Kemper IGCC and the Plant Daniel Units 1 and 2 scrubber project, which the applicable courts subsequently granted.

Under the Sierra Club Settlement Agreement, the Company agreed to, among other things, fund a $15 million grant payable over a 15-year period for an energy efficiency and renewable program and contribute $2 million to a conservation fund. In accordance with the Sierra Club Settlement Agreement, the Company paid $7 million in 2014, recognized in other income (expense), net in the statement of operations. In addition, and consistent with the Company's ongoing evaluation of recent environmental rules and regulations, the Company agreed to retire, repower with natural gas, or convert to an alternative non-fossil fuel source Plant Sweatt Units 1 and 2 (80 MWs) no later than December 2018. The Company also agreed that it would cease burning coal and other solid fuel at Plant Watson Units 4 and 5 (750 MWs) and begin operating those units solely on natural gas no later than April 2015, and cease burning coal and other solid fuel at Plant Greene County Units 1 and 2 (200 MWs) and begin operating those units solely on natural gas no later than April 2016. See Note 3 under "Retail Regulatory Matters – Environmental Compliance Overview Plan" for additional information.

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4. JOINT OWNERSHIP AGREEMENTS
The Company and Alabama Power own, as tenants in common, Units 1 and 2 (total capacity of 500 MWs) at Greene County Steam Plant, which is located in Alabama and operated by Alabama Power. Additionally, the Company and Gulf Power, own as tenants in common, Units 1 and 2 (total capacity of 1,000 MWs) at Plant Daniel, which is located in Mississippi and operated by the Company.
In August 2014, a decision was made to cease coal operations at Greene County Steam Plant and convert to natural gas no later than April 16, 2016. As a result, active construction projects related to these assets were cancelled in September 2014. Associated amounts in CWIP of $5.6 million, reflecting the Company's share of the costs, were subsequently transferred to regulatory assets. See Note 3 under "Retail Regulatory Matters-Environmental Compliance Overview Plan" herein for additional information.
At December 31, 2014, the Company's percentage ownership and investment in these jointly-owned facilities in commercial operation were as follows:

Generating Plant	Company Ownership		Plant in Service (in thousands)	Accumulated Depreciation	CWIP
Greene County					
Units 1 and 2	40	%	$102,384	$51,911	$902
Daniel					
Units 1 and 2	50	%	$299,440	$155,606	$286,240

The Company's proportionate share of plant operating expenses is included in the statements of operations and the Company is responsible for providing its own financing.
See Note 3 under "Retail Regulatory Matters – Environmental Compliance Overview Plan" for additional information.
5. INCOME TAXES
On behalf of the Company, Southern Company files a consolidated federal income tax return and combined state income tax returns for the States of Alabama and Mississippi. Under a joint consolidated income tax allocation agreement, each 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:

	2014 (in thousands)	2013	2012
Federal —			
Current	$(431,077)	$23,345	$1,212
Deferred	183,461	(342,870)	16,994
	(247,616)	(319,525)	18,206
State —			
Current	455	5,219	1,656
Deferred	(38,044)	(53,529)	694
	(37,589)	(48,310)	2,350
Total	$(285,205)	$(367,835)	$20,556

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

	2014	2013
	(in thousands)	
Deferred tax liabilities —		
Accelerated depreciation	$1,068,242	$371,553
Property basis differences	—	130,679
ECM under recovered	—	1,777
Regulatory assets associated with AROs	19,299	16,764
Pensions and other benefits	35,200	23,769
Regulatory assets associated with employee benefit obligations	67,727	33,127
Regulatory assets associated with the Kemper IGCC	61,561	30,708
Rate differential	89,040	56,074
Federal effect of state deferred taxes	1,279	30,615
Fuel clause under recovered	3,288	—
Other	52,215	35,583
Total	1,397,851	730,649
Deferred tax assets —		
Fuel clause over recovered	—	7,741
Estimated loss on Kemper IGCC	631,326	472,000
Pension and other benefits	92,232	57,999
Property insurance	24,315	23,693
Premium on long-term debt	20,694	23,736
Unbilled fuel	14,535	12,136
AROs	19,299	16,764
Interest rate hedges	4,544	5,094
Kemper rate factor - regulatory liability retail	108,312	36,210
Property basis difference	263,430	—
ECM over recovered	905	—
Deferred state tax assets	56,736	—
Other	15,111	18,094
Total	1,251,439	673,467
Total deferred tax liabilities, net	146,412	57,182
Portion included in (accrued) prepaid income taxes, net	121,049	15,626
Deferred state tax asset	17,388	—
Accumulated deferred income taxes	$284,849	$72,808

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

At December 31, 2014, the tax-related regulatory assets were $226.2 million. These assets are primarily attributable to tax benefits flowed through to customers in prior years, deferred taxes previously recognized at rates lower than the current enacted tax law, and to taxes applicable to capitalized interest.

At December 31, 2014, the tax-related regulatory liabilities were $9.4 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 operations. Credits for non-Kemper IGCC

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related deferred ITCs amortized in this manner amounted to $1.4 million, $1.2 million, and $1.2 million for 2014, 2013, and 2012, respectively. At December 31, 2014, all non-Kemper IGCC ITCs available to reduce federal income taxes payable had been utilized.

In 2010, the Company began recognizing ITCs associated with the construction expenditures related to the Kemper IGCC. At December 31, 2014, the Company had $276.4 million in unamortized ITCs associated with the Kemper IGCC, which will be amortized over the life of the Kemper IGCC once placed in service 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 operation in accordance with the Internal Revenue Code. A portion of the tax credits will be subject to recapture upon successful completion of SMEPA's proposed purchase of an undivided interest in the Kemper IGCC.

Effective Tax Rate

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

	2014	2013	2012
Federal statutory rate	(35.0)%	(35.0)%	35.0%
State income tax, net of federal deduction	(4.0)	(3.7)	1.3
Non-deductible book depreciation	0.1	0.1	0.3
AFUDC-equity	(7.8)	(5.0)	(18.6)
Other	0.1	(0.1)	(1.2)
Effective income tax rate (benefit rate)	(46.6)%	(43.7)%	16.8%

The increase in the Company's 2014 effective tax rate (benefit rate), as compared to 2013, is primarily due to an increase in non-taxable AFUDC equity. The decrease in the Company's 2013 effective tax rate, as compared to 2012, is primarily due to an increase in the estimated losses associated with the Kemper IGCC and an increase in non-taxable AFUDC equity.

Unrecognized Tax Benefits

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

	2014	2013	2012
	(in thousands)		
Unrecognized tax benefits at beginning of year	$3,840	$5,755	$4,964
Tax positions from current periods	58,148	226	1,186
Tax positions from prior periods	102,833	(2,141)	(26)
Settlements with taxing authorities	—	—	(369)
Balance at end of year	$164,821	$3,840	$5,755

The increases in tax positions from current periods and prior periods for 2014 relate to deductions for R&E expenditures related to the Kemper IGCC. See Note 3 under "Integrated Coal Gasification Combined Cycle – Section 174 Research and Experimental Deduction" for more information. The decrease in tax positions from prior periods for 2013 relates primarily to the tax accounting method change for repairs related to generation assets. See "Tax Method of Accounting for Repairs" below for additional information.

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

	2014	2013	2012
	(in thousands)		
Tax positions impacting the effective tax rate	$4,341	$3,840	$3,656
Tax positions not impacting the effective tax rate	160,480	—	2,099
Balance of unrecognized tax benefits	$164,821	$3,840	$5,755

The tax positions impacting the effective tax rate primarily relate to state income tax credits. The tax positions not impacting the effective tax rate for 2014 relate to a deduction for R&E related to the Kemper IGCC. The tax positions not impacting the

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effective tax rate for 2012 relate to the tax accounting method change for repairs related to generation assets. 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:

	2014	2013	2012
	(in thousands)		
Interest accrued at beginning of year	$1,171	$772	$680
Interest accrued during the year	1,698	399	92
Balance at end of year	$2,869	$1,171	$772

The Company classifies interest on tax uncertainties as interest expense. The Company did not accrue any penalties on uncertain tax positions.
It is reasonably possible that the amount of the unrecognized tax benefits could change within 12 months. The settlement of federal and state audits could impact the balances significantly. At this time, an estimate of the range of reasonably possible outcomes cannot be determined.
The IRS has finalized its audits of Southern Company's consolidated federal income tax returns through 2012. Southern Company has filed its 2013 federal income tax return and has received a partial acceptance letter from the IRS; however, the IRS has not finalized its audit. Southern Company is a participant in the Compliance Assurance Process of the IRS. The audits for the Company's state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2011.
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, in April 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. In September 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 continues to review this guidance; however, these regulations are not expected to have a material impact on the Company's financial statements.
6. FINANCING
Bank Term Loans
In January 2014, the Company 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 the proceeds were used for working capital and other general corporate purposes, including the Company’s continuous construction program.
At December 31, 2014 and 2013, the Company had $775 million and $525 million of bank loans outstanding, respectively, which are reflected in the statements of capitalization as securities due within one year and long-term debt.
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 any long-term debt payable to affiliated trusts, other hybrid securities, and any securitized debt relating to the securitization of certain costs of the Kemper IGCC. At December 31, 2014, the Company was in compliance with its debt limits.
Senior Notes
At December 31, 2014 and 2013, the Company had $1.1 billion of senior notes outstanding. These senior notes are effectively subordinated to the secured debt of the Company. See "Plant Daniel Revenue Bonds" below for additional information regarding the Company's secured indebtedness.
Plant Daniel Revenue Bonds

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

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These bonds are secured by Plant Daniel Units 3 and 4 and certain related personal property. The bonds were recorded at fair value as of the date of assumption, or $346.1 million, reflecting a premium of $76.1 million.
Securities Due Within One Year
A summary of scheduled maturities and redemptions of securities due within one year at December 31, 2014 and 2013 was as follows:

	2014	2013
	(in millions)	
Bank term loans	$775.0	$—
Revenue bonds	—	11.3
Capitalized leases	2.7	2.5
Outstanding at December 31	$777.7	$13.8

Maturities through 2019 applicable to total long-term debt are as follows: $777.7 million in 2015, $302.8 million in 2016, $37.9 million in 2017, $3.1 million in 2018, and $128.2 million in 2019.
Pollution Control Revenue Bonds
Pollution control obligations represent loans to the Company from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control and solid waste disposal facilities. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. The amount of tax-exempt pollution control revenue bonds outstanding at December 31, 2014 and 2013 was $82.7 million.
Other Revenue Bonds
Other revenue bond obligations represent loans to the Company from a public authority of funds derived from the sale by such authority of revenue bonds issued to finance a portion of the costs of constructing the Kemper IGCC and related facilities.
In 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 the Company. 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 the Company. In May 2014 and August 2014, the MBFC issued $12.3 million and $10.5 million, respectively, aggregate principal amount of MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2013A for the benefit of the Company and proceeds were used to reimburse the Company for the cost of the acquisition, construction, equipping, installation, and improvement of certain equipment and facilities for the lignite mining facility related to the Kemper IGCC. In December 2014, the MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2013A of $22.87 million and Series 2013B of $11.25 million were paid at maturity. The Company had $50.0 million of such obligations outstanding related to tax-exempt revenue bonds at December 31, 2014 and 2013. The Company had no obligation as of December 31, 2014 and $11.3 million of such obligations related to taxable revenue bonds outstanding at December 31, 2013. Such amounts are reflected in the statements of capitalization as long-term senior notes and debt.
The Company's agreements relating to the taxable revenue bonds include covenants limiting debt levels consistent with those described above under "Bank Term Loans."
Capital Leases
In September 2013, the Company entered into an agreement to sell the air separation unit for the Kemper IGCC and also entered into a 20-year nitrogen supply agreement. The nitrogen supply agreement was determined to be a sale/leaseback agreement which resulted in a capital lease obligation at December 31, 2014 of $80.0 million with an annual interest rate of 4.9%. There are no contingent rentals in the contract and a portion of the monthly payment specified in the agreement is related to executory costs for the operation and maintenance of the air separation unit and

excluded from the minimum lease payments. The minimum lease payments for 2014 were $6.5 million and will be $6.5 million each year thereafter. Amortization of the capital lease asset for the air separation unit will begin when the Kemper IGCC is placed in service.

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Other Obligations
In 2012, January 2014, and October 2014, the Company received $150 million, $75 million, and $50 million, respectively, interest-bearing refundable deposits from SMEPA to be applied to the sale price for the pending sale of an undivided interest in the Kemper IGCC. Until the sale is closed, the deposits bear interest at the Company's AFUDC rate adjusted for income taxes, which was 10.134% per annum for 2014, 9.932% per annum for 2013, and 9.967% per annum for 2012, and are refundable to SMEPA upon termination of the APA related to such purchase or within 15 days of a request by SMEPA for a full or partial refund.
In May 2014, the Company issued a 19-month floating rate promissory note to Southern Company for a loan bearing interest based on one-month LIBOR. This loan was for $220 million aggregate principal amount and the proceeds were used for working capital and other general corporate purposes, including the Company's construction program. This loan was repaid in September 2014.
Assets Subject to Lien
The revenue bonds assumed in conjunction with the purchase of Plant Daniel Units 3 and 4 are secured by Plant Daniel Units 3 and 4 and certain related personal property. There are no agreements or other arrangements among the Southern Company system companies under which the assets of one company have been pledged or otherwise made available to satisfy the obligations of Southern Company or another of its other subsidiaries.
Outstanding Classes of Capital Stock
The Company currently has preferred stock (including depositary shares which represent one-fourth of a share of preferred stock) and common stock authorized and outstanding. The preferred stock of the Company contains a feature that allows the holders to elect a majority of the Company's board of directors if preferred dividends are not paid for four consecutive quarters. Because such a potential redemption-triggering event is not solely within the control of the Company, this preferred stock is presented as "Cumulative Redeemable Preferred Stock" in a manner consistent with temporary equity under applicable accounting standards. The Company's preferred stock and depositary preferred stock, without preference between classes, rank senior to the Company's common stock with respect to payment of dividends and voluntary or involuntary dissolution. The preferred stock and depositary preferred stock is subject to redemption at the option of the Company at a redemption price equal to 100% of the liquidation amount of the stock.
Dividend Restrictions
The Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital.
Bank Credit Arrangements
At December 31, 2014, committed credit arrangements with banks were as follows:

Expires				Executable Term-Loans		Due Within One Year	
2015	2016	Total	Unused	One Year	Two Years	Term Out	No Term Out
(in millions)							
$135	$165	$300	$300	$25	$40	$65	$70

Subject to applicable market conditions, the Company expects to renew its bank credit arrangements, as needed, prior to expiration.
Most of these bank credit arrangements require payment of commitment fees based on the unused portions of the commitments or to maintain compensating balances with the banks. Commitment fees average less than 1/4 of 1% for the Company. Compensating balances are not legally restricted from withdrawal.
Most of these bank credit arrangements contain covenants that limit the Company's debt levels to 65% of total capitalization, as defined in the agreements. For purposes of these definitions, debt excludes certain hybrid securities and any securitized debt relating to the securitization of certain costs of the Kemper IGCC.

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A portion of the $300 million unused credit with banks is allocated to provide liquidity support to the Company's variable rate pollution control revenue bonds and its commercial paper borrowings. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2014 was $40.1 million. The Company makes short-term borrowings primarily through a commercial paper program that has the liquidity support of the Company's committed bank credit arrangements.
At December 31, 2014 and 2013, there was no short-term debt outstanding.
7. COMMITMENTS
Fuel and Purchased Power Agreements
To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement and delivery of fossil fuel which are not recognized on the balance sheets. In 2014, 2013, and 2012, the Company incurred fuel expense of $573.9 million, $491.3 million, and $411.2 million, respectively, the majority of which was purchased under long-term commitments. The Company expects that a substantial amount of its future fuel needs will continue to be purchased under long-term commitments.
Coal commitments include a management fee associated with a 40-year management contract with Liberty Fuels related to the Kemper IGCC with the remaining amount as of December 31, 2014 of $38.4 million. Additional commitments for fuel will be required to supply the Company's future needs.
SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and all of the other traditional operating companies and Southern Power. Under these agreements, each of the traditional operating companies and Southern Power may be jointly and severally liable. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the other traditional operating companies to ensure the Company will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power as a contracting party under these agreements.
Operating Leases
The Company has operating lease agreements with various terms and expiration dates. Total rent expense was $12.7 million, $10.1 million, and $11.1 million for 2014, 2013, and 2012, respectively.
The Company and Gulf Power have jointly entered into operating lease agreements for aluminum railcars for the transportation of coal at Plant Daniel. The Company has the option to purchase the railcars at the greater of lease termination value or fair market value, or to renew the leases at the end of the lease term. The Company has one remaining operating lease which has 229 aluminum railcars. The Company and Gulf Power also have separate lease agreements for other railcars that do not contain a purchase option.
The Company's share (50%) of the leases, charged to fuel stock and recovered through the fuel cost recovery clause, was $4.9 million in 2014, $3.1 million in 2013, and $3.6 million in 2012. The Company's annual railcar lease payments for 2015 through 2017 will average approximately $1.6 million. The Company has no lease obligations for the period 2018 and thereafter.
In addition to railcar leases, the Company has other operating leases for fuel handling equipment at Plants Daniel and Watson and operating leases for barges and tow/shift boats for the transport of coal at Plant Watson. The Company's share (50% at Plant Daniel and 100% at Plant Watson) of the leases for fuel handling was charged to fuel handling expense in the amount of $0.2 million annually from 2012 through 2014. The Company's annual lease payment for 2015 is expected to be $0.1 million for fuel handling equipment. The Company charged to fuel stock and recovered through fuel cost recovery the barge transportation leases in the amount of $7.5 million in 2014, $6.7 million in 2013, and $7.3 million in 2012 related to barges and tow/shift boats. The Company's annual lease payment for 2015 with respect to these barge transportation leases is expected to be $1.8 million.
8. STOCK COMPENSATION
Stock Options
Southern Company provides non-qualified stock options through its Omnibus Incentive Compensation Plan to a large segment of the Company's system employees ranging from line management to executives. As of December 31, 2014,

there were 244 current and former employees of the Company 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. The Company generally recognizes stock option expense on a straight-line basis over the vesting period which equates to the requisite service period; however, for employees who are eligible for retirement, the total cost is expensed at the

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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.

For the years ended December 31, 2014, 2013, and 2012, employees of the Company were granted stock options for 578,256 shares, 345,830 shares, and 278,709 shares, respectively. The weighted average grant-date fair value of stock options granted during 2014, 2013, and 2012, derived using the Black-Scholes stock option pricing model, was $2.20, $2.93, and $3.39, respectively.

The compensation cost and tax benefits related to the grant of Southern Company stock options to the Company's employees and the exercise of stock options are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. No cash proceeds are received by the Company upon the exercise of stock options. The amounts were not material for any year presented. As of December 31, 2014, the amount of unrecognized compensation cost related to stock option awards not yet vested was immaterial.

The total intrinsic value of options exercised during the years ended December 31, 2014, 2013, and 2012 was $5.4 million, $2.7 million, and $4.9 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $2.1 million, $1.1 million, and $1.9 million for the years ended December 31, 2014, 2013, and 2012, respectively. As of December 31, 2014, the aggregate intrinsic value for the options outstanding and options exercisable was $18.4 million and $12.3 million, respectively.

Performance Shares

Southern Company provides performance share award units through its Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. The performance share units granted under the plan vest at the end of a three-year performance period which equates to the requisite service period. Employees that retire prior to the end of the three-year period receive a pro rata number of shares, issued at the end of the performance period, based on actual months of service prior to retirement. The value of the award units is based on Southern Company's total shareholder return (TSR) over the three-year performance period which measures Southern Company's relative performance against a group of industry peers. The performance shares are delivered in common stock following the end of the performance period based on Southern Company's actual TSR and may range from 0% to 200% of the original target performance share amount. Performance share units held by employees of a company undergoing a change in control vest upon the change in control.

For the years ended December 31, 2014, 2013, and 2012, employees of the Company were granted performance share units of 49,579, 36,769, and 33,077, respectively. The weighted average grant-date fair value of performance share units granted during 2014, 2013, and 2012, determined using a Monte Carlo simulation model to estimate the TSR of Southern Company's stock among the industry peers over the performance period, was $37.54, $40.50, and $41.99, respectively.

The Company recognizes compensation expense on a straight-line basis over the three-year performance period without remeasurement. Compensation expense for awards where the service condition is met is recognized regardless of the actual number of shares issued. For the years ended December 31, 2014, 2013, and 2012, total compensation cost for performance share units recognized in income was $1.7 million, $1.5 million, and $1.2 million, respectively, with the related tax benefit also recognized in income of $0.6 million, $0.6 million, and $0.4 million, respectively. The compensation cost and tax benefits related to the grant of Southern Company performance share units to the Company's employees are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. As of December 31, 2014, there was $1.8 million of total unrecognized compensation cost related to performance share award units that will be recognized over a weighted-average period of approximately 20 months.

9. FAIR VALUE MEASUREMENTS

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

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.

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- 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, 2014, 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, 2014:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in thousands)			
Assets:				
Energy-related derivatives	$—	$65	$—	$65
Cash equivalents	114,900	—	—	114,900
Total	$114,900	$65	$—	$114,965
Liabilities:				
Energy-related derivatives	$—	$45,429	$—	$45,429

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 thousands)			
Assets:				
Energy-related derivatives	$—	$4,803	$—	$4,803
Cash equivalents	125,000	—	—	125,000
Total	$125,000	$4,803	$—	$129,803
Liabilities:				
Energy-related derivatives	$—	$10,281	$—	$10,281
Foreign currency derivatives	—	1	—	1
Total	$—	$10,282	$—	$10,282

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. Foreign currency derivatives are also standard over-the-counter financial products valued using the market approach. Inputs for foreign currency derivatives are from observable market sources. See Note 10 for additional information on how these derivatives are used.

NOTES (continued)
Mississippi Power Company 2014 Annual Report

As of December 31, 2014 and 2013, 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:

As of December 31, 2014:	Fair Value (in thousands)	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
Cash equivalents:				
Money market funds	$114,900	None	Daily	Not applicable
As of December 31, 2013:				
Cash equivalents:				
Money market funds	$125,000	None	Daily	Not applicable

The money market funds are short-term investments of excess funds in various money market mutual funds, which are portfolios of short-term debt securities. The money market funds are regulated by the SEC and typically receive the highest rating from credit rating agencies. Regulatory and rating agency requirements for money market funds include minimum credit ratings and maximum maturities for individual securities and a maximum weighted average portfolio maturity. Redemptions are available on a same day basis up to the full amount of the Company's investment in the money market funds.

As of December 31, 2014 and 2013, other financial instruments for which the carrying amount did not equal fair value were as follows:

	Carrying Amount	Fair Value
	(in thousands)	
Long-term debt:		
2014	$2,328,476	$2,382,050
2013	$2,098,639	$2,045,519

The fair values are determined using Level 2 measurements and are based on quoted market prices for the same or similar issues or on the current rates offered to the Company.

10. DERIVATIVES

The Company is exposed to market risks, primarily commodity price risk and interest rate risk and occasionally foreign currency risk. To manage the volatility attributable to these exposures, the Company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a gross basis. See Note 9 for additional information. In the statements of cash flows, the cash impacts of settled energy-related and interest rate derivatives are recorded as operating activities and the cash impacts of settled foreign currency derivatives are recorded as investing activities.

Energy-Related Derivatives

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, the Company has limited exposure to market volatility in commodity fuel prices and prices of electricity. The Company manages fuel-hedging programs, implemented per the guidelines of the Mississippi PSC, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility.

To mitigate residual risks relative to movements in electricity prices, the Company may enter into physical fixed-price or heat rate contracts for the purchase and sale of electricity through the wholesale electricity market. To mitigate residual risks relative to movements in gas prices, the Company may enter into fixed-price contracts for natural gas purchases; however, a significant portion of contracts are priced at market.

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

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NOTES (continued)
Mississippi Power Company 2014 Annual Report

- Regulatory Hedges – Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the Company's fuel-hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the respective fuel cost recovery clauses.
- Cash Flow Hedges – Gains and losses on energy-related derivatives designated as cash flow hedges which are mainly used to hedge anticipated purchases and sales and are initially deferred in OCI before being recognized in the statements of operations 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 operations 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, 2014, the net volume of energy-related derivative contracts for natural gas positions for the Company, together with the longest hedge date over which it is hedging its exposure to the variability in future cash flows for forecasted transactions and the longest date for derivatives not designated as hedges, were as follows:

Net Purchased mmBtu	Longest Hedge Date	Longest Non-Hedge Date
(in millions)		
54	2018	—

For cash flow hedges, the amounts expected to be reclassified from accumulated OCI to earnings for the next 12-month period ending December 31, 2015 are immaterial.

Interest Rate Derivatives

The Company may also enter into interest rate derivatives to hedge exposure to changes in interest rates. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings. The derivatives employed as hedging instruments are structured to minimize ineffectiveness, which is recorded directly to income.

At December 31, 2014, there were no interest rate derivatives outstanding.

The estimated pre-tax losses that will be reclassified from accumulated OCI to interest expense for the 12-month period ending December 31, 2015 are $1.4 million. The Company has deferred gains and losses that are expected to be amortized into earnings through 2022.

Foreign Currency Derivatives

The Company may enter into foreign currency derivatives to hedge exposure to changes in foreign currency exchange rates arising from purchases of equipment denominated in a currency other than U.S. dollars. Derivatives related to a firm commitment in a foreign currency transaction are accounted for as a fair value hedge where the derivatives' fair value gains or losses and the hedged items' fair value gains or losses are both recorded directly to earnings. Derivatives related to a forecasted transaction are accounted for as a cash flow hedge where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings. Any ineffectiveness is typically recorded directly to earnings; however, the Company has regulatory approval allowing it to defer any ineffectiveness associated with firm commitments related to the Kemper IGCC to a regulatory asset. During 2011, certain fair value hedges were de-designated and subsequently settled in 2012. The ineffectiveness related to the de-designated hedges was recorded as a regulatory asset and was immaterial to the Company. The derivatives employed as hedging instruments are structured to minimize ineffectiveness.

At December 31, 2014, there were no foreign currency derivatives outstanding.

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NOTES (continued)
Mississippi Power Company 2014 Annual Report

Derivative Financial Statement Presentation and Amounts
At December 31, 2014 and 2013, the fair value of energy-related derivatives and foreign currency derivatives was reflected in the balance sheets as follows:

Derivative Category	Asset Derivatives Balance Sheet Location	2014	2013	Liability Derivatives Balance Sheet Location	2014	2013
		(in thousands)			(in thousands)	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	$30	$3,352	Other current liabilities	$26,259	$3,652
	Other deferred charges and assets	22	1,451	Other deferred credits and liabilities	19,159	6,629
Total derivatives designated as hedging instruments for regulatory purposes		$52	$4,803		$45,418	$10,281
Derivatives designated as hedging instruments in cash flow and fair value hedges						
Foreign currency derivatives:	Other current assets	$—	$—	Other current liabilities	$—	$1
Total		$52	$4,803		$45,418	$10,282

Energy-related derivatives not designated as hedging instruments were immaterial for 2014 and 2013. The derivative contracts of the Company are not subject to master netting arrangements or similar agreements and are reported gross on the Company's financial statements. Some of these energy-related 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, 2014 and 2013 are presented in the following tables.

Fair Value

Assets	2014	2013	Liabilities	2014	2013
	(in thousands)			(in thousands)	
Energy-related derivatives presented in the Balance Sheet [(a)]	$65	$4,803	Energy-related derivatives presented in the Balance Sheet [(a)]	$45,429	$10,282
Gross amounts not offset in the Balance Sheet [(b)]	(64)	(3,856)	Gross amounts not offset in the Balance Sheet [(b)]	(64)	(3,856)
Net energy-related derivative assets	$1	$947	Net energy-related derivative liabilities	$45,365	$6,426

(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.

NOTES (continued)
Mississippi Power Company 2014 Annual Report

At December 31, 2014 and 2013, 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	2014	2013	Unrealized Gains Balance Sheet Location	2014	2013
		(in thousands)			(in thousands)	
Energy-related derivatives:	Other regulatory assets, current	$(26,259)	$(3,652)	Other regulatory liabilities, current	$30	$3,352
	Other regulatory assets, deferred	(19,159)	(6,629)	Other regulatory liabilities, deferred	22	1,451
Total energy-related derivative gains (losses)		$(45,418)	$(10,281)		$52	$4,803

The pre-tax effects of unrealized gains (losses) arising from energy-related derivative instruments not designated as hedging instruments was immaterial for 2014 and 2013.
For the years ended December 31, 2014, 2013, and 2012, the pre-tax effects of derivatives designated as cash flow hedging instruments on the statements of operations were as follows:

Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Recognized in OCI on Derivative (Effective Portion)			Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)			
					Amount		
Derivative Category	2014	2013	2012	Statements of Operations Location	2014	2013	2012
	(in thousands)				(in thousands)		
Energy-related derivatives	$—	$—	$—	Fuel	$—	$—	$—
Interest rate derivatives	—	—	(774)	Interest Expense	(1,375)	(1,375)	(1,073)
Total	$—	$—	$(774)		$(1,375)	$(1,375)	$(1,073)

There was no material ineffectiveness recorded in earnings for any period presented.
For the years ended December 31, 2014, 2013, and 2012, the pre-tax effects of energy-related derivatives not designated as hedging instruments on the statements of operations were immaterial.
For the years ended December 31, 2014 and 2013, the pre-tax effects of foreign currency derivatives designated as fair value hedging instruments on the Company's statements of operations were immaterial. For the year ended December 31, 2012, the pre-tax effect of foreign currency derivatives designated as fair value hedging instruments, which include a pretax loss associated with the de-designated hedges prior to de-designation, was a $0.6 million gain. These amounts were offset by changes in the fair value of the purchase commitment related to equipment purchases. Therefore, there is no impact on the Company's statements of operations.
Contingent Features
The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain affiliated companies. At December 31, 2014, the Company's collateral posted with its derivative counterparties was immaterial.
At December 31, 2014, the fair value of derivative liabilities with contingent features was $9.9 million. However, because of joint and several liability features underlying these derivatives, the maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $54.5

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.

NOTES (continued)
Mississippi Power Company 2014 Annual Report

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P or with counterparties who have posted collateral to cover potential credit exposure. The Company has also established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk. Therefore, the Company does not anticipate a material adverse effect on the financial statements as a result of counterparty nonperformance.

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NOTES (continued)
Mississippi Power Company 2014 Annual Report

11. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)
Summarized quarterly financial information for 2014 and 2013 is as follows:

Quarter Ended	Operating Revenues	Operating Income (Loss)	Net Income (Loss) After Dividends on Preferred Stock
	(in thousands)		
March 2014	$331,161	$(325,460)	$(172,048)
June 2014	310,975	56,021	62,495
September 2014	354,623	(349,010)	(195,070)
December 2014	245,852	(70,721)	(24,058)
March 2013	$245,934	$(429,148)	$(246,321)
June 2013	306,435	(388,395)	(219,110)
September 2013	325,206	(79,890)	(24,115)
December 2013	267,582	(24,412)	12,921

As a result of the revisions to the cost estimate for the Kemper IGCC, the Company recorded total pre-tax charges to income for the estimated probable losses on the Kemper IGCC of $70.0 million ($43.2 million after tax) in the fourth quarter 2014, $418.0 million ($258.1 million after tax) in the third quarter 2014, $380.0 million ($234.7 million after tax) in the first quarter 2014, $40.0 million ($24.7 million after tax) in the fourth quarter 2013, $150.0 million ($92.6 million after tax) in the third quarter 2013, $450.0 million ($277.9 million after tax) in the second quarter 2013, $462.0 million ($285.3 million after tax) in the first quarter 2013, and $78.0 million ($48.2 million after tax) in the fourth quarter 2012. In the aggregate, the Company has incurred charges of $2.05 billion ($1.26 billion after tax) as a result of changes in the cost estimate for the Kemper IGCC through December 31, 2014. See Note 3 under "Integrated Coal Gasification Combined Cycle" for additional information.
The Company's business is influenced by seasonal weather conditions.

SELECTED FINANCIAL AND OPERATING DATA 2010-2014
Mississippi Power Company 2014 Annual Report

	2014	2013	2012	2011	2010
Operating Revenues (in thousands)	$1,242,611	$1,145,157	$1,035,996	$1,112,877	$1,143,068
Net Income (Loss) After Dividends on Preferred Stock (in thousands)	$(328,681)	$(476,625)	$99,942	$94,182	$80,217
Cash Dividends on Common Stock (in thousands)	$—	$71,956	$106,800	$75,500	$68,600
Return on Average Common Equity (percent)	(15.43)	(24.28)	7.14	10.54	11.49
Total Assets (in thousands)	$6,756,728	$5,848,209	$5,373,621	$3,671,842	$2,476,321
Gross Property Additions (in thousands)	$1,388,711	$1,773,332	$1,665,498	$1,205,704	$340,162
Capitalization (in thousands):					
Common stock equity	$2,084,260	$2,176,551	$1,749,208	$1,049,217	$737,368
Redeemable preferred stock	32,780	32,780	32,780	32,780	32,780
Long-term debt	1,630,487	2,167,067	1,564,462	1,103,596	462,032
Total (excluding amounts due within one year)	$3,747,527	$4,376,398	$3,346,450	$2,185,593	$1,232,180
Capitalization Ratios (percent):					
Common stock equity	55.6	49.7	52.3	48.0	59.8
Redeemable preferred stock	0.9	0.7	1.0	1.5	2.7
Long-term debt	43.5	49.6	46.7	50.5	37.5
Total (excluding amounts due within one year)	100.0	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	152,453	152,585	152,265	151,805	151,944
Commercial	33,496	33,250	33,112	33,200	33,121
Industrial	482	480	472	496	504
Other	175	175	175	175	187
Total	186,606	186,490	186,024	185,676	185,756
Employees (year-end)	1,478	1,344	1,281	1,264	1,280

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SELECTED FINANCIAL AND OPERATING DATA 2010-2014 (continued)
Mississippi Power Company 2014 Annual Report

	2014	2013	2012	2011	2010
Operating Revenues (in thousands):					
Residential	$239,330	$241,956	$226,847	$246,510	$256,994
Commercial	257,189	265,506	250,860	263,256	266,406
Industrial	290,902	289,272	262,978	275,752	267,588
Other	7,222	2,405	6,768	6,945	6,924
Total retail	794,643	799,139	747,453	792,463	797,912
Wholesale — non-affiliates	322,659	293,871	255,557	273,178	287,917
Wholesale — affiliates	107,210	34,773	16,403	30,417	41,614
Total revenues from sales of electricity	1,224,512	1,127,783	1,019,413	1,096,058	1,127,443
Other revenues	18,099	17,374	16,583	16,819	15,625
Total	$1,242,611	$1,145,157	$1,035,996	$1,112,877	$1,143,068
Kilowatt-Hour Sales (in thousands):					
Residential	2,126,115	2,087,704	2,045,999	2,162,419	2,296,157
Commercial	2,859,617	2,864,947	2,915,934	2,870,714	2,921,942
Industrial	4,942,689	4,738,714	4,701,681	4,586,356	4,466,560
Other	40,595	40,139	38,588	38,684	38,570
Total retail	9,969,016	9,731,504	9,702,202	9,658,173	9,723,229
Wholesale — non-affiliates	4,190,812	3,929,177	3,818,773	4,009,637	4,284,289
Wholesale — affiliates	2,899,814	931,153	571,908	648,772	774,375
Total	17,059,642	14,591,834	14,092,883	14,316,582	14,781,893
Average Revenue Per Kilowatt-Hour (cents)*:					
Residential	11.26	11.59	11.09	11.40	11.19
Commercial	8.99	9.27	8.60	9.17	9.12
Industrial	5.89	6.10	5.59	6.01	5.99
Total retail	7.97	8.21	7.70	8.21	8.21
Wholesale	6.06	6.76	6.19	6.52	6.51
Total sales	7.18	7.73	7.23	7.66	7.63
Residential Average Annual Kilowatt-Hour Use Per Customer	13,934	13,680	13,426	14,229	15,130
Residential Average Annual Revenue Per Customer	$1,568	$1,585	$1,489	$1,622	$1,693
Plant Nameplate Capacity Ratings (year-end) (megawatts)	3,867	3,088	3,088	3,156	3,156
Maximum Peak-Hour Demand (megawatts):					
Winter	2,618	2,083	2,168	2,618	2,792
Summer	2,345	2,352	2,435	2,462	2,638
Annual Load Factor (percent)	59.4	64.7	61.9	59.1	57.9
Plant Availability Fossil-Steam (percent)**	87.6	89.3	91.5	87.7	93.8
Source of Energy Supply (percent):					
Coal	39.7	32.7	22.8	34.9	43.0
Oil and gas	55.3	57.1	63.9	51.5	41.9
Purchased power —					
From non-affiliates	1.4	2.0	2.0	1.4	1.3
From affiliates	3.6	8.2	11.3	12.2	13.8
Total	100.0	100.0	100.0	100.0	100.0

* The average revenue per kilowatt-hour (cents) is based on booked operating revenues and will not match billed revenue per kilowatt-hour.

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

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SOUTHERN POWER COMPANY
FINANCIAL SECTION

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Southern Power Company and Subsidiary Companies 2014 Annual Report

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

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2014.

/s/ Oscar C. Harper, IV
Oscar C. Harper, IV
President and Chief Executive Officer
/s/ William C. Grantham
William C. Grantham
Vice President, Chief Financial Officer, and Treasurer
March 2, 2015

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM
To the Board of Directors of
Southern Power Company

We have audited the accompanying consolidated balance sheets of Southern Power Company and Subsidiary Companies (the Company) (a wholly owned subsidiary of The Southern Company) as of December 31, 2014 and 2013, and the related consolidated statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2014. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements (pages II-462 to II-484) present fairly, in all material respects, the financial position of Southern Power Company and Subsidiary Companies as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America.
/s/ Deloitte & Touche LLP
Atlanta, Georgia
March 2, 2015

DEFINITIONS

Term	Meaning
Adobe	Adobe Solar, LLC
Alabama Power	Alabama Power Company
AOCI	Accumulated other comprehensive income
Apex	Apex Nevada Solar, LLC
ASC	Accounting Standards Codification
Campo Verde	Campo Verde Solar, LLC
Clean Air Act	Clean Air Act Amendments of 1990
CO_2	Carbon dioxide
CWIP	Construction work in progress
EMC	Electric Membership Corporation
EPA	U.S. Environmental Protection Agency
EPE	El Paso Electric Company
FERC	Federal Energy Regulatory Commission
First Solar	First Solar, Inc.
FPL	Florida Power & Light Company
GAAP	Generally accepted accounting principles
Georgia Power	Georgia Power Company
Gulf Power	Gulf Power Company
Imperial Valley	SG2 Imperial Valley, LLC
IRS	Internal Revenue Service
ITC	Investment tax credit
Kay Wind	Kay Wind, LLC
KWH	Kilowatt-hour
Macho Springs	Macho Springs Solar, LLC
Mississippi Power	Mississippi Power Company
mmBtu	Million British thermal units
Moody's	Moody's Investors Service, Inc.
MW	Megawatt
MWH	Megawatt hour
OCI	Other comprehensive income
power pool	The operating arrangement whereby the integrated generating resources of the traditional operating companies and Southern Power Company are subject to joint commitment and dispatch in order to serve their combined load obligations
PPA	Power purchase agreement
S&P	Standard and Poor's Rating Services, a division of The McGraw Hill Companies, Inc.
SCE	Southern California Edison Company
SCS	Southern Company Services, Inc. (the Southern Company system service company)
SEC	U.S. Securities and Exchange Commission
SG2 Holdings	SG2 Holdings, LLC
Southern Company system	The Southern Company, the traditional operating companies, Southern Power Company, Southern Electric Generating Company, Southern Nuclear, SCS, SouthernLINC Wireless, and other subsidiaries
SouthernLINC Wireless	Southern Communications Services, Inc.
Southern Nuclear	Southern Nuclear Operating Company, Inc.

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DEFINITIONS
(continued)

SRE	Southern Renewable Energy, Inc.
SRP	Southern Renewable Partnerships, LLC
STR	Southern Turner Renewable Energy, LLC
traditional operating companies	Alabama Power, Georgia Power, Gulf Power, and Mississippi Power
TRE	Turner Renewable Energy, LLC

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Southern Power Company and Subsidiary Companies 2014 Annual Report
OVERVIEW
Business Activities
Southern Power Company and its subsidiaries (the Company) construct, acquire, own, and manage generation assets, including renewable energy projects, and sell electricity at market-based rates in the wholesale market. The Company continually seeks opportunities to execute its strategy to create value through various transactions including acquisitions and sales of assets, construction of new power plants, and entry into PPAs primarily with investor owned utilities, independent power producers, municipalities, and electric cooperatives. In general, the Company has constructed or acquired new generating capacity only after entering into long-term PPAs for the new facilities.
The Company and TRE, through STR, a jointly-owned subsidiary owned 90% by Southern Power Company, acquired all of the outstanding membership interests of Adobe and Macho Springs on April 17, 2014 and May 22, 2014, respectively. The two solar facilities began commercial operation in May 2014 with the approximate 20-MW Adobe solar photovoltaic facility serving a PPA with SCE through 2034 and the approximate 50-MW Macho Springs solar photovoltaic facility serving a PPA with EPE also through 2034.
On October 22, 2014, the Company, through its subsidiaries SRP and SG2 Holdings, acquired all of the outstanding membership interests of Imperial Valley from a wholly-owned subsidiary of First Solar, the developer of the project. Imperial Valley constructed and owns an approximately 150-MW solar photovoltaic facility in Southern California. The solar facility began commercial operation on November 26, 2014 and at that time a subsidiary of First Solar was admitted as a minority member of SG2 Holdings. The entire output of the plant is contracted under a 25-year PPA with San Diego Gas & Electric Company, a subsidiary of Sempra Energy (SDG&E).
See FUTURE EARNINGS POTENTIAL – "Acquisitions" herein and Note 2 to the financial statements for additional information.
As of December 31, 2014, the Company had generating units totaling 9,074 MWs nameplate capacity in commercial operation, after taking into consideration its equity ownership percentage of the solar facilities. The average remaining duration of the Company's wholesale contracts is approximately 10 years, which reduces remarketing risk. The Company's renewable assets, including biomass and solar, have contract coverage in excess of 20 years. Taking into account the PPAs and capacity from the Taylor County and Decatur County Solar Projects, as discussed in "FUTURE EARNINGS POTENTIAL – Construction Projects" herein, and the acquisition of Kay Wind, which is expected to close in the fourth quarter 2015, as discussed in "FUTURE EARNINGS POTENTIAL – Acquisitions" herein, the Company had an average of 77% of its available capacity covered for the next five years (through 2019) and an average of 70% of its available capacity covered for the next 10 years (through 2024). The Company's future earnings will depend on the parameters of the wholesale market and the efficient operation of its wholesale generating assets. See FUTURE EARNINGS POTENTIAL herein for additional information.
Key Performance Indicators
To evaluate operating results and to ensure the Company's ability to meet its contractual commitments to customers, the Company focuses on several key performance indicators, including peak season equivalent forced outage rate (Peak Season EFOR), contract availability, and net income. Peak Season EFOR defines the hours during peak demand times when the Company's generating units are not available due to forced outages (a low metric is optimal). Contract availability measures the percentage of scheduled hours delivered. Net income is the primary measure of the Company's financial performance. The Company's actual performance in 2014 met or surpassed targets in these key performance areas. See RESULTS OF OPERATIONS herein for additional information on the Company's net income for 2014.
Earnings
The Company's 2014 net income was $172.3 million, a $6.8 million, or 4.1%, increase from 2013. The increase was primarily due to a decrease in income taxes primarily as a result of federal ITCs for new plants placed in service in 2014 and an increase in energy revenue from non-affiliates primarily related to new solar contracts. This increase was

partially offset by increased depreciation, other operations and maintenance expenses, and interest expense.
The Company's 2013 net income was $165.5 million, a $9.8 million, or 5.6%, decrease from 2012. The decrease was primarily due to an increase in other operations and maintenance expenses and depreciation primarily due to an increase in costs related to scheduled outages and new plants placed in service, higher fuel and purchased power expenses, and higher interest expense. The

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decrease was partially offset by an increase in capacity and energy revenues from non-affiliates and lower income tax expense associated with the net impact of federal ITCs received in 2013.

RESULTS OF OPERATIONS

A condensed statement of income follows:

	Amount	Increase (Decrease) from Prior Year	
	2014	2014	2013
	(in millions)		
Operating revenues	$1,501.2	$226.0	$89.2
Fuel	596.3	122.5	47.5
Purchased power	170.9	64.5	13.1
Other operations and maintenance	237.0	28.7	35.2
Depreciation and amortization	220.2	44.9	32.7
Taxes other than income taxes	21.5	0.1	2.1
Total operating expenses	1,245.9	260.7	130.6
Operating income	255.3	(34.7)	(41.4)
Interest expense, net of amounts capitalized	89.0	14.5	12.0
Other income (expense), net	5.6	9.7	(3.1)
Income taxes (benefit)	(3.2)	(49.1)	(46.7)
Net income	175.1	9.6	(9.8)
Less: Net income attributable to noncontrolling interests	2.8	2.8	—
Net income attributable to Southern Power Company	$172.3	$6.8	$(9.8)

Operating Revenues

Operating revenues for 2014 were $1.5 billion, reflecting a $226.0 million, or 17.7%, increase from 2013. Details of operating revenues are as follows:

	2014	2013	2012
		(in millions)	
Capacity revenues —			
Affiliates	$117.8	$126.0	$125.9
Non-affiliates	428.4	446.4	372.6
Total	546.2	572.4	498.5
Energy revenues —			
Affiliates	35.4	23.8	35.6
Non-affiliates	602.2	427.1	346.7
Total	637.6	450.9	382.3
Total PPA revenues	1,183.8	1,023.3	880.8
Revenues not covered by PPA	314.6	245.3	298.0
Other revenues	2.8	6.6	7.2
Total Operating Revenues	$1,501.2	$1,275.2	$1,186.0

The increase in operating revenues was primarily due to a $121.0 million increase in energy revenues under PPAs with non-affiliates, resulting from a 24.0% increase in KWH sales, primarily due to increased demand and customer scheduling, and a 69.6% increase in the average price of energy, primarily due to higher natural gas prices, as well as, a $54.6 million increase which was the result of new solar contracts served by Plants Adobe, Macho Springs, and Imperial Valley, which began in 2014, and Plants Campo Verde and Spectrum, which began in 2013. Also contributing to the increase was a $34.2 million increase in

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energy sales not covered by PPAs and a $33.3 million increase in sales under the Intercompany Interchange Contract (IIC), primarily due to increased generation and higher cost affiliate power. Additionally, there was an increase of $11.5 million in energy revenues under PPAs with affiliates primarily as a result of increased demand and customer scheduling. This increase was partially offset by an $18.0 million decrease in capacity revenues from non-affiliates primarily due to lower customer demand and the expiration of certain requirements contracts and an $8.1 million decrease in capacity revenues from affiliates primarily due to contract expirations.

Operating revenues in 2013 were $1.3 billion, an $89.2 million, or 7.5%, increase from 2012. The increase was primarily due to a $73.8 million increase in capacity revenues under PPAs with non-affiliates, resulting from a 10.6% increase in the total MWs of capacity under contract, primarily due to a new PPA served by Plant Nacogdoches, which began in June 2012, and an increase in capacity amounts under existing PPAs. Also contributing to the increase was an $80.4 million increase in energy sales under PPAs with non-affiliates, reflecting a 29.6% increase in the average price of energy and a $7.8 million increase related to new solar contracts, which began in 2013, served by Plants Campo Verde and Spectrum. This increase was partially offset by an $11.8 million decrease in energy sales under PPAs with affiliates, reflecting a 48.1% decrease in KWH sales primarily due to lower demand, partially offset by a 28.9% increase in the average price of energy. The increase in energy revenues from PPAs was partially offset by a $52.4 million decrease in energy sales not covered by PPAs, reflecting a 30.5% decrease in KWH sales primarily due to lower demand, partially offset by an 18.6% increase in the average price of energy.

Wholesale revenues from sales to affiliate companies will vary depending on demand and the availability and cost of generating resources at each company. Sales to affiliate companies that are not covered by PPAs are made in accordance with the IIC, as approved by the FERC.

Wholesale revenues from sales to non-affiliates will vary depending on the energy demand of those customers and their generation capacity, as well as the market prices of wholesale energy compared to the cost of the Company's energy. Increases and decreases in revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not have a significant impact on net income.

Capacity revenues are an integral component of the Company's PPAs with both affiliate and non-affiliate customers and generally represent the greatest contribution to net income. Energy under the PPAs is generally sold at variable cost or is indexed to published gas indices. Energy revenues also include fees for support services, fuel storage, and unit start charges.

See FUTURE EARNINGS POTENTIAL – "Power Sales Agreements" below for additional information regarding the Company's PPAs.

Fuel and Purchased Power Expenses

Fuel costs constitute the single largest expense for the Company. Additionally, the Company purchases a portion of its electricity needs from the wholesale market.

Details of the Company's fuel and purchased power expenditures are as follows:

	2014	2013	2012
		(in millions)	
Fuel	$596.3	$473.8	$426.3
Purchased power-non-affiliates	104.9	76.0	80.4
Purchased power-affiliates	66.0	30.4	12.9
Total fuel and purchased power expenses	$767.2	$580.2	$519.6

The Company's PPAs for natural gas-fired generation generally provide that the purchasers are responsible for substantially all of the cost of fuel. Consequently, any increase or decrease in fuel cost is generally accompanied by an increase or decrease in related fuel revenue and does not have a significant impact on net income. The Company is responsible for the cost of fuel for generating units that are not covered under PPAs. Power from these generating units is sold into the market or sold to affiliates under the IIC.

Purchased power expenses will vary depending on demand and the availability and cost of generating resources throughout the Southern Company system and other contract resources. Load requirements are submitted to the Southern Company system power pool on an hourly basis and are fulfilled with the lowest cost alternative, whether that is generation owned by Southern Power Company, affiliate-owned generation, or external purchases.

In 2014, total fuel and purchased power expenses increased $187.0 million, or 32.2%, compared to 2013, primarily due to a 19.7% increase in the average cost of natural gas and a 24.0% increase in the average cost of purchased power. The increase

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reflected a 29.6% increase in the volume of KWHs purchased primarily as a result of higher demand and the availability of lower cost affiliate power.

In 2013, total fuel and purchased power expenses increased $60.6 million, or 11.7%, compared to 2012, primarily due to a 28.8% increase in the average cost of natural gas and a 21.1% increase in the average cost of purchased power. The increase was partially offset by a 12.8% net decrease in the volume of KWHs generated and purchased primarily due to lower demand and the availability of lower cost affiliate power.

In 2014, fuel expense increased $122.5 million, or 25.9%, compared to 2013. The increase was primarily due to a $91.3 million increase associated with the average cost of natural gas per KWH generated as well as a $31.2 million increase associated with the volume of KWHs generated.

In 2013, fuel expense increased $47.5 million, or 11.2%, compared to 2012. The increase was primarily due to a $104.1 million increase associated with the average cost of natural gas per KWH generated, partially offset by a $58.5 million decrease associated with the volume of KWHs generated.

In 2014, purchased power expense increased $64.5 million, or 60.6%, compared to 2013. The increase was primarily due to a $33.0 million increase associated with the average cost of purchased power and a $31.5 million increase associated with the volume of KWHs purchased.

In 2013, purchased power expense increased $13.1 million, or 14.0%, compared to 2012. The increase was primarily due to an $18.3 million increase associated with the average cost of purchased power, partially offset by a $5.3 million decrease associated with the volume of KWHs purchased.

Other Operations and Maintenance Expenses

In 2014, other operations and maintenance expenses increased $28.7 million, or 13.8%, compared to 2013. The increase was primarily due to a $10.6 million increase in other generation expenses primarily related to labor and repairs as well as a $7.8 million increase primarily as a result of increased business development costs and support services. Also contributing to the increase was a $6.6 million increase in costs related to new plants placed in service, including Plants Spectrum and Campo Verde in 2013, and Plants Adobe, Macho Springs and Imperial Valley in 2014, and a $2.2 million increase in employee compensation.

In 2013, other operations and maintenance expenses increased $35.2 million, or 20.4%, compared to 2012. The increase was primarily due to a $21.8 million increase related to scheduled outage costs at Plants Franklin and Wansley, $6.2 million in additional costs related to new plant additions, including Plants Nacogdoches, Apex, Granville, and Cleveland in 2012 and Plants Spectrum and Campo Verde in 2013, and a $1.4 million increase in transmission costs.

Depreciation and Amortization

In 2014, depreciation and amortization increased $44.9 million, or 25.6%, compared to 2013. The increase was primarily due to a $25.2 million increase in depreciation resulting from an increase in plant in service, including the addition of Plants Spectrum and Campo Verde in 2013, and Plants Adobe, Macho Springs, and Imperial Valley in 2014, an $8.4 million increase related to equipment retirements resulting from accelerated outage work, and a $5.9 million increase in component depreciation resulting from increased production at gas-fired plants.

In 2013, depreciation and amortization increased $32.7 million, or 22.9%, compared to 2012. The increase was primarily due to a $23.8 million increase in depreciation resulting from an increase in plant in service, including the additions of Plants Nacogdoches, Apex, Granville, and Cleveland in 2012 and Plants Spectrum and Campo Verde in 2013, a $3.5 million increase for outage related capital costs, and a $2.4 million increase resulting from higher depreciation rates driven by major outages occurring in 2013.

See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Depreciation" herein for additional information regarding the Company's ongoing review of depreciation estimates and change to component depreciation. See also Note 1 to the financial statements under "Depreciation" for additional information.

Interest Expense, Net of Amounts Capitalized

In 2014, interest expense, net of amounts capitalized increased $14.5 million, or 19.5%, compared to 2013. The increase was primarily due to a $9.3 million decrease in capitalized interest resulting from the completion of Plants Spectrum and Campo Verde in 2013 and an increase of $5.1 million in interest expense related to senior notes.
In 2013, interest expense, net of amounts capitalized increased $12.0 million, or 19.2%, compared to 2012. The increase was primarily due to a $19.1 million decrease in capitalized interest resulting from the completion of Plants Nacogdoches and

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Cleveland in 2012, partially offset by a $9.2 million increase in capitalized interest associated with the construction of Plants Spectrum and Campo Verde in 2013.

Other Income (Expense), Net

In 2014, other income (expense), net increased $9.7 million compared to 2013. The increase in 2014 was primarily due to the recognition of a bargain purchase gain arising from a solar acquisition. Additionally, net income attributable to noncontrolling interests of approximately $3.9 million was included in other income (expense), net in 2013. See Note 10 to the financial statements for additional information on noncontrolling interests.

In 2013, other income (expense), net decreased $3.1 million compared to 2012. The decrease in 2013 was primarily due to increased earnings of STR, which resulted in a larger allocation of earnings to noncontrolling interest.

Income Taxes (Benefit)

In 2014, income taxes (benefit) decreased $49.1 million, or 107.0%, compared to 2013. The decrease was primarily due to a $20.1 million increase in tax benefits primarily from federal ITCs for solar plants placed in service in 2014, a $19.9 million decrease associated with lower pre-tax earnings, and a $10.5 million reduction in deferred income taxes as a result of the impact of state apportionment changes and beneficial changes in certain state income tax laws.

In 2013, income taxes (benefit) decreased $46.7 million, or 50.4%, compared to 2012. The decrease was primarily due to a $24.2 million increase in tax benefits from federal ITCs for solar plants placed in service in 2013 and a $20.9 million decrease associated with lower pre-tax earnings.

See Note 5 to the financial statements under "Effective Tax Rate" for additional information.

Effects of Inflation

The Company is party to long-term contracts reflecting market-based rates, including inflation expectations. Any adverse effect of inflation on the Company's results of operations has not been substantial in recent years.

FUTURE EARNINGS POTENTIAL

General

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's competitive wholesale business. These factors include: the Company's ability to achieve sales growth while containing costs; regulatory matters; creditworthiness of customers; total generating capacity available in the Company's market areas; the successful remarketing of capacity as current contracts expire; and the Company's ability to execute its acquisition and value creation strategy, including successfully expanding investments in renewable energy projects, and to construct generating facilities, including the impact of ITCs.

Other factors that could influence future earnings include weather, demand, cost of generating units within the power pool, and operational limitations.

Power Sales Agreements

The Company's natural gas and biomass sales are primarily through long-term PPAs that consist of two types of agreements. The first type, referred to as a unit or block sale, is a customer purchase from a dedicated plant unit where all or a portion of the generation from that unit is reserved for that customer. The Company typically has the ability to serve the unit or block sale customer from an alternate resource. The second type, referred to as requirements service, provides that the Company serve the customer's capacity and energy requirements from a combination of the customer's own generating units and from Company resources not dedicated to serve unit or block sales. The Company has rights to purchase power provided by the requirements customers' resources when economically viable.

The Company has assumed or entered into PPAs with some of Southern Company's traditional operating companies, other investor owned utilities, independent power producers, municipalities, electric cooperatives, and an energy marketing firm. Although some of the Company's PPAs are with the traditional operating companies, the Company's generating facilities are not in the traditional operating companies' regulated rate bases, and the Company is not able to seek recovery from the traditional operating companies' ratepayers for construction, repair, environmental, or maintenance costs. The Company expects that the capacity payments in the PPAs will produce sufficient cash flows to cover costs, pay debt service, and provide an equity return.

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However, the Company's overall profit will depend on numerous factors, including efficient operation of its generating facilities and demand under the Company's PPAs.

As a general matter, substantially all of the Company's PPAs (excluding solar) provide that the purchasers are responsible for either procuring the fuel or reimbursing the Company for the cost of fuel relating to the energy delivered under such PPAs. To the extent a particular generating facility does not meet the operational requirements contemplated in the PPAs, the Company may be responsible for excess fuel costs. With respect to fuel transportation risk, most of the Company's PPAs provide that the counterparties are responsible for transporting the fuel to the particular generating facility.

The Company's solar sales are also through long-term PPAs where the customer purchases the entire energy output of a dedicated solar facility.

Capacity charges that form part of the PPA payments (excluding solar) are designed to recover fixed and variable operation and maintenance costs based on dollars-per-kilowatt year or energy charges based on dollars-per-MW hour. In general, to reduce the Company's exposure to certain operation and maintenance costs, it has long-term service agreements (LTSA) with General Electric International, Inc., Siemens Electric, Inc., First Solar, and NVT Licenses, LLC relating to such vendors' applicable equipment.

Many of the Company's PPAs have provisions that require the posting of collateral or an acceptable substitute guarantee in the event that S&P or Moody's downgrades the credit ratings of the counterparty to an unacceptable credit rating or if the counterparty is not rated or fails to maintain a minimum coverage ratio. The PPAs are expected to provide the Company with a stable source of revenue during their respective terms.

The Company is working to maintain and expand its share of the wholesale market. The Company expects that additional demand for capacity will begin to develop within some of its market areas beginning in the 2015-2017 timeframe. Taking into account the PPAs and capacity from the Taylor County and Decatur County Solar Projects, as discussed in "Construction Projects" herein, and the acquisition of Kay Wind, which is expected to close in the fourth quarter 2015, as discussed in "Acquisitions" herein, the Company had an average of 77% of its available capacity covered for the next five years (through 2019) and an average of 70% of its available capacity covered for the next 10 years (through 2024).

Environmental Matters

The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; the Endangered Species Act; and related federal and state regulations. Compliance with possible additional federal or state legislation or regulations related to global climate change, air quality, water quality, or other environmental and health concerns could also significantly affect the Company.

New environmental legislation or regulations, such as requirements related to greenhouse gases or changes to existing statutes or regulations, could affect many areas of the Company's operations. While the Company's PPAs generally contain provisions that permit charging the counterparty with some of the new costs incurred as a result of changes in environmental laws and regulations, the full impact of any such regulatory or legislative changes cannot be determined at this time.

Because the Company's units are newer gas-fired and renewable generating facilities, costs associated with environmental compliance for these facilities have been less significant than for similarly situated coal-fired generating facilities or older gas-fired generating facilities. Environmental, natural resource, and land use concerns, including the applicability of air quality limitations, the potential presence of wetlands or threatened and endangered species, the availability of water withdrawal rights, uncertainties regarding aesthetic impacts such as increased light or noise, and concerns about potential adverse health impacts can, however, increase the cost of siting and operating any

type of future electric generating facility. The impact of such statutes and regulations on the Company cannot be determined at this time.
Environmental Statutes and Regulations
Air Quality
Each of the states in which the Company has fossil generation is subject to the requirements of the Cross State Air Pollution Rule (CSAPR). CSAPR is an emissions trading program that limits SO_2 and nitrogen oxide emissions from power plants in 28 states in two phases, with Phase I beginning in 2015 and Phase II beginning in 2017. In 2012, the U.S. Court of Appeals for the District of Columbia Circuit vacated CSAPR in its entirety, but on April 29, 2014, the U.S. Supreme Court overturned that decision and remanded the case back to the U.S. Court of Appeals for the District of Columbia Circuit for further proceedings. The U.S. Court

of Appeals for the District of Columbia Circuit granted the EPA's motion to lift the stay of the rule, and the first phase of CSAPR took effect on January 1, 2015.

In 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.

In February 2013, the EPA proposed a rule that would require certain states to revise the provisions of their State Implementation Plans (SIPs) relating to the regulation of excess emissions at industrial facilities, including fossil fuel-fired generating facilities, during periods of startup, shut-down, or malfunction (SSM). The EPA proposed to supplement the 2013 proposed rule on September 17, 2014, making it more stringent. The EPA has entered into a settlement agreement requiring it to finalize the proposed rule by May 22, 2015. The proposed rule would require states subject to the rule (including Alabama, Florida, Georgia, and North Carolina) to revise their SSM provisions within 18 months after issuance of the final rule.

The Company has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the current and proposed environmental requirements discussed above. The impacts of CSAPR, the NSPS for CTs, and the SSM rule on the Company cannot be determined at this time and will depend on the specific provisions of the proposed rules, the resolution of pending and future legal challenges, and/or the development and implementation of rules at the state level. These regulations could result in additional compliance costs that could affect results of operations, cash flows, and financial condition if such costs are not recovered through PPAs. Further, higher costs that are recovered through regulated rates at other utilities could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

Water Quality

The EPA's final rule establishing standards for reducing effects on fish and other aquatic life caused by new and existing cooling water intake structures at existing power plants and manufacturing facilities became effective on October 14, 2014. The effect of this final rule will depend on the results of additional studies and implementation of the rule by regulators based on site-specific factors. The ultimate impact of this rule will also depend on the outcome of ongoing legal challenges and cannot be determined at this time.

In June 2013, the EPA published a proposed rule which requested comments on a range of potential regulatory options for addressing revised technology-based limits for certain wastestreams from steam electric power plants. The EPA has entered into a consent decree requiring it to finalize revisions to the steam electric effluent guidelines by September 30, 2015. The ultimate impact of the rule will also depend on the specific technology requirements of the final rule and the outcome of any legal challenges and cannot be determined at this time.

These proposed and final water quality regulations could result in additional capital expenditures and compliance costs. Also, results of operations, cash flows, and financial condition could be impacted if such costs are not recovered through PPAs. Based on a preliminary assessment of the impact of the proposed rules, the Company estimates compliance costs to be immaterial. Further, higher costs that are recovered through regulated rates at other utilities could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

Global Climate Issues

In 2014, the EPA published three sets of proposed standards that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. On January 8, 2014, the EPA published proposed standards for new units, and, on June 18, 2014, the EPA published proposed standards governing existing units, known as the Clean Power Plan, and separate standards governing CO_2 emissions from modified and reconstructed units. The EPA's proposed Clean Power Plan establishes guidelines for states to develop plans to address CO_2 emissions from existing fossil fuel-fired electric generating units. The EPA's proposed guidelines establish state-specific interim and final CO_2 emission rate goals to be achieved between 2020 and 2029 and in 2030 and thereafter. The proposed guidelines and standards could result in operational restrictions and material compliance costs, including capital expenditures, which could affect future unit retirement and replacement decisions. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates or through market-based contracts. Further, higher costs that are recovered through regulated rates at other utilities could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

The Southern Company system filed comments on the EPA's proposed Clean Power Plan on December 1, 2014. These comments addressed legal and technical issues in addition to providing a preliminary estimated cost of complying with the proposed

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guidelines utilizing one of the EPA's compliance scenarios. Costs associated with this proposal could be significant to the utility industry and the Southern Company system. However, the ultimate financial and operational impact of the proposed Clean Power Plan on the Southern Company system cannot be determined at this time and will depend upon numerous known and unknown factors. Some of the unknown factors include: the structure, timing, and content of the EPA's final guidelines; individual state implementation of these guidelines, including the potential that state plans impose different standards; additional rulemaking activities in response to legal challenges and related court decisions; the impact of future changes in generation and emissions-related technology and costs; the impact of future decisions regarding unit retirement and replacement, including the type and amount of any such replacement capacity; and the time periods over which compliance will be required.

Over the past several years, the U.S. Congress has also 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.

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 Company's 2013 greenhouse gas emissions were approximately 9 million metric tons of CO_2 equivalent. The preliminary estimate of the Company's 2014 greenhouse gas emissions on the same basis is approximately 11 million metric tons of CO_2 equivalent. The level of greenhouse gas emissions from year to year will depend on the level of generation, the mix of fuel sources, and other factors.

Income Tax Matters

Tax Credits

In 2009, President Obama signed into law the American Recovery and Reinvestment Act of 2009 (ARRA). Major tax incentives in the ARRA included renewable energy incentives. In January 2013, the American Taxpayer Relief Act of 2012 (ATRA) was signed into law. The ATRA retroactively extended several renewable energy incentives through 2013, including extending federal ITCs for biomass projects which began construction before January 1, 2014. The current law provides for a 30% federal ITC for solar facilities placed in service through 2016 and, unless extended, will adjust to 10% for solar facilities placed in service thereafter. The Company qualified for ITCs related to Plants Adobe, Apex, Campo Verde, Cimarron, Granville, Imperial Valley, Macho Springs, Nacogdoches, and Spectrum, which have had and will continue to have a material impact on cash flows and net income. On December 19, 2014, the Tax Increase Prevention Act of 2014 (TIPA) was signed into law. The TIPA extended the production tax credit for wind and certain other renewable sources of electricity to facilities for which construction had commenced by the end of 2014. See Note 1 to the financial statements under "Income and Other Taxes" and Note 5 to the financial statements under "Effective Tax Rate" for additional information.

Bonus Depreciation

The TIPA additionally extended 50% bonus depreciation for property placed in service in 2014 (and for certain long-term production-period projects to be placed in service in 2015). The extension of 50% bonus depreciation will have a positive impact on the Company's cash flows, of approximately $110 million.

Acquisitions

Adobe Solar, LLC

On April 17, 2014, the Company and TRE, through STR, a jointly-owned subsidiary owned 90% by the Company, acquired all of the outstanding membership interests of Adobe from Sun Edison, LLC, the original developer of the project. Adobe constructed and owns an approximately 20-MW solar generating facility in Kern County, California. The solar facility began commercial operation on May 21, 2014 and the entire output of the plant is contracted under a 20-year PPA with SCE. See Note 2 to the financial statements for additional information.

Macho Springs Solar, LLC

On May 22, 2014, the Company and TRE, through STR, acquired all of the outstanding membership interests of Macho Springs from First Solar Development, LLC, the original developer of the project. Macho Springs constructed and owns an approximately 50-MW solar photovoltaic facility in Luna County, New Mexico. The solar facility began commercial operation on May 23, 2014 and the entire output of the plant is contracted under a 20-year PPA with EPE. See Note 2 to the financial statements for additional information.

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SG2 Imperial Valley, LLC
On October 22, 2014, the Company, through its subsidiaries SRP and SG2 Holdings, acquired all of the outstanding membership interests of Imperial Valley from a wholly-owned subsidiary of First Solar, the developer of the project. Imperial Valley constructed and owns an approximately 150-MW solar photovoltaic facility in Southern California. The solar facility began commercial operation on November 26, 2014 and the entire output of the plant is contracted under a 25-year PPA with SDG&E.
In connection with this acquisition, at substantial completion, on November 26, 2014, a subsidiary of First Solar was admitted as a minority member of SG2 Holdings. Ultimately, the Company indirectly owns 100% of the class A membership interests of SG2 Holdings and is entitled to 51% of all cash distributions from SG2 Holdings, and First Solar indirectly owns 100% of the class B membership interests of SG2 Holdings and is entitled to 49% of all cash distributions from SG2 Holdings. In addition, the Company is entitled to substantially all of the federal tax benefits with respect to this transaction. See Note 2 to the financial statements for additional information.
Kay County Wind Facility
On February 24, 2015, the Company, through its wholly-owned subsidiary SRE, entered into a purchase agreement with Kay Wind Holdings, LLC, a wholly-owned subsidiary of Apex Clean Energy Holdings, LLC, the developer of the project, to acquire all of the outstanding membership interests of Kay Wind for approximately $492 million, with potential purchase price adjustments based on performance testing. Kay Wind is constructing an approximately 299-MW wind facility in Kay County, Oklahoma. The wind facility is expected to begin commercial operation in late 2015, and the entire output of the facility is contracted under separate 20-year PPAs with Westar Energy, Inc. and Grand River Dam Authority. The acquisition is expected to close in the fourth quarter 2015 subject to Kay Wind achieving certain financing, construction, and project milestones, and various customary conditions to closing, and is included in the capital program estimates described under FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein. See Note 2 to the financial statements for additional information.
Construction Projects
Taylor County Solar Project
On December 17, 2014, the Company announced that it will build an approximately 131-MW solar photovoltaic facility in Taylor County, Georgia. Construction of the facility is expected to begin in September 2015. Commercial operation is scheduled to begin in the fourth quarter of 2016, and the entire output of the facility is contracted under separate 25-year PPAs with Cobb Electric Membership Corp., Flint Electric Membership Corp., and Sawnee Electric Membership Corp. The total estimated cost of the facility is expected to be between $230 million and $250 million, and is included in the capital program estimates described under FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein.
Decatur County Solar Projects
In February 2015, the Company announced that it will build two solar photovoltaic facilities, the Decatur Parkway Solar Project and the Decatur County Solar Project. These two projects, approximately 80-MW and 19-MW, respectively, will be constructed on separate sites in Decatur County, Georgia. The construction of the Decatur Parkway Solar Project commenced in February 2015 while the construction of the Decatur County Solar Project is expected to commence in June 2015. Both projects are expected to begin commercial operation in late 2015, and the entire output of each project is contracted to Georgia Power. The output of the Decatur Parkway Solar Project is contracted under a 25-year PPA with Georgia Power and the entire output of the Decatur County Solar Project is contracted under a separate 20-year PPA with Georgia Power. The total estimated cost of the facilities is expected to be between $200 million and $220 million, which includes the acquisition price for all of the outstanding membership interests of Decatur Parkway Solar Project, LLC and Decatur County Solar Project, LLC from TradeWind Energy, Inc. and is included in the capital program estimates described under FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein.
Other Matters

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

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been caused by CO_2 and other emissions and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters.

The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

The 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 the Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has reviewed and discussed the following critical accounting policies and estimates with the Audit Committee of Southern Company's Board of Directors.

Revenue Recognition

The Company's revenue recognition depends on appropriate classification and documentation of transactions in accordance with GAAP. In general, the Company's power sale transactions can be classified in one of four categories: leases, non-derivatives or normal sale derivatives, derivatives designated as cash flow hedges, and derivatives not designated as hedges. For more information on derivative transactions, see FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" herein and Notes 1 and 9 to the financial statements. The Company's revenues are dependent upon significant judgments used to determine the appropriate transaction classification, which must be documented upon the inception of each contract.

Lease Transactions

The Company considers the following factors to determine whether the sales contract is a lease:

- Assessing whether specific property is explicitly or implicitly identified in the agreement;
- Determining whether the fulfillment of the arrangement is dependent on the use of the identified property; and
- Assessing whether the arrangement conveys to the purchaser the right to use the identified property.

If the contract meets the above criteria for a lease, the Company performs further analysis as to whether the lease is classified as operating, financing, or sales-type. All of the Company's power sales contracts classified as leases are accounted for as operating leases and the associated lease revenue is recognized on a straight-line basis over the term of the contract. Energy revenues and other contingent revenues are recognized in the period the energy is delivered or the service is rendered. All revenues under solar PPAs are accounted for as contingent revenues and recognized as services are performed.

Non-Derivative and Normal Sale Derivative Transactions

If the power sales contract is not classified as a lease, the Company further considers the following factors to determine proper classification:

- Assessing whether the contract meets the definition of a derivative;
- Assessing whether the contract meets the definition of a capacity contract;
- Assessing the probability at inception and throughout the term of the individual contract that the contract will result in physical delivery; and
- Ensuring that the contract quantities do not exceed available generating capacity (including purchased capacity).

Contracts that do not meet the definition of a derivative or are designated as normal sales (i.e. capacity contracts which provide for the sale of electricity that involve physical delivery in quantities within the Company's available generating capacity) are accounted for as executory contracts. The related capacity revenue is recognized on an accrual basis in amounts equal to the lesser of the cumulative levelized amount or the cumulative amount billable under the contract over the respective contract periods. Energy revenues are recognized in the period the energy is delivered or the service is rendered. Revenues are recorded on a gross basis in accordance with GAAP. Contracts recorded on the accrual basis represented the majority of the Company's operating revenues.

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Cash Flow Hedge Transactions
The Company further considers the following in designating other derivative contracts for the sale of electricity as cash flow hedges of anticipated sale transactions:
- Identifying the hedging instrument, the hedged transaction, and the nature of the risk being hedged; and
- Assessing hedge effectiveness at inception and throughout the contract term.

These contracts are accounted for on a fair value basis and are recorded in AOCI over the life of the contract. Realized gains and losses are then recognized in revenues as incurred.
Mark-to-Market Transactions
Contracts for sales of electricity, which meet the definition of a derivative and that either do not qualify or are not designated as normal sales or as cash flow hedges, are accounted for on a fair value basis and are recorded in net income.
Impairment of Long Lived Assets and Intangibles
The Company's investments in long-lived assets are primarily generation assets, whether in service or under construction. The Company's intangible assets consist of acquired PPAs from certain acquisitions that are amortized over the term of the respective PPAs, and goodwill resulting from certain acquisitions. The Company evaluates the carrying value of these assets in accordance with accounting standards whenever indicators of potential impairment exist, or annually in the case of goodwill. Examples of impairment indicators could include significant changes in construction schedules, current period losses combined with a history of losses or a projection of continuing losses, a significant decrease in market prices, and the inability to remarket generating capacity for an extended period. If an indicator exists, the asset is tested for recoverability by comparing the asset carrying value to the sum of the undiscounted expected future cash flows directly attributable to the asset. If the estimate of undiscounted future cash flows is less than the carrying value of the asset, the fair value of the asset is determined and a loss is recorded. A high degree of judgment is required in developing estimates related to these evaluations, which are based on projections of various factors, including the following:
- Future demand for electricity based on projections of economic growth and estimates of available generating capacity;
- Future power and natural gas prices, which have been quite volatile in recent years; and
- Future operating costs.

Acquisition Accounting
The Company acquires generation assets as part of its overall growth strategy. The Company accounts for business acquisitions from non-affiliates as business combinations. Accordingly, the Company includes these operations in the consolidated financial statements from the respective date of acquisition. The purchase price, including contingent consideration, if any, of each acquisition is 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 is allocated based on the relative fair value of assets acquired. Any due diligence or transition costs incurred by the Company for successful or potential acquisitions are expensed as incurred.
Depreciation
Beginning in 2014, the Company changed to component depreciation, where the depreciation of the original cost of assets is computed principally by the straight-line method over the estimated useful lives of assets determined by management. Certain generation assets are depreciated on a units-of-production basis, using hours or starts, to better match outage and maintenance costs to the usage of and revenues from these assets. The primary assets in property, plant, and equipment are power plants, which have estimated useful lives ranging from 35 to 45 years. The Company reviews its estimated useful lives and salvage values on an ongoing basis. The results of these reviews could result in changes that could have a material impact on net income in the near term.
When property subject to depreciation is retired or otherwise disposed of in the normal course of business, the applicable cost and accumulated depreciation is removed from the accounts and a gain or loss is recognized.

Prior to 2014, the Company computed depreciation on the original cost of assets under the straight-line method and applied a composite depreciation rate based on the assets' estimated useful lives determined by management.

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Investment Tax Credits
Under the ARRA and ATRA, certain construction costs related to renewable generating assets are eligible for federal ITCs. A high degree of judgment is required in determining which construction expenditures qualify for federal ITCs. See Note 1 to the financial statements under "Income and Other Taxes" for additional information.
Recently Issued Accounting Standards
On May 28, 2014, the Financial Accounting Standards Board issued ASC 606, Revenue from Contracts with Customers. ASC 606 revises the accounting for revenue recognition and is effective for fiscal years beginning after December 15, 2016. The Company continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.
FINANCIAL CONDITION AND LIQUIDITY
Overview
The Company's financial condition remained stable at December 31, 2014. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements as needed to meet its future capital and liquidity needs. See "Sources of Capital" herein for additional information on lines of credit.
Net cash provided from operating activities totaled $602.4 million in 2014. Net cash provided from operating activities totaled $604.4 million in 2013, an increase of $31.2 million compared to 2012. This increase was primarily due to an increase in cash received from federal ITCs.
Net cash used for investing activities totaled $813.7 million, $696.0 million, and $332.5 million in 2014, 2013, and 2012, respectively. Net cash used for investing activities in 2014 was primarily due to the Adobe, Macho Springs, and Imperial Valley acquisitions. Net cash used for investing activities in 2013 was primarily due to the Campo Verde acquisition and the construction of the Spectrum and Campo Verde solar facilities. Net cash used for investing activities in 2012 was primarily due to the Apex, Spectrum, and Granville acquisitions, construction of Plants Nacogdoches and Cleveland, and payments pursuant to LTSAs.
Net cash provided from financing activities totaled $217.2 million and $131.8 million in 2014 and 2013, respectively. Net cash used for financing activities totaled $229.0 million in 2012. Net cash provided from financing activities in 2014 was primarily due to the issuance of commercial paper. Net cash provided from financing activities in 2013 was primarily the result of the issuance of new senior notes. Net cash used for financing activities in 2012 was primarily due to payment of common stock dividends and a decrease in notes payable.
Significant asset changes in the balance sheet during 2014 included an increase in property, plant, and equipment, primarily due to the acquisition of Adobe, Macho Springs, and Imperial Valley and an increase in deferred income taxes, current, due to the carryforward of federal ITCs arising from certain solar acquisitions.
Significant liability and stockholder's equity changes in the balance sheet during 2014 included an increase in federal ITCs due to new solar facilities placed in service, including Adobe, Macho Springs, and Imperial Valley and an increase in deferred income taxes primarily due to bonus depreciation on those new solar facilities, and an increase in notes payable due to the issuance of commercial paper.
Sources of Capital
The Company plans to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily from operating cash flows, short-term debt, securities issuances, term loans, 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.
The issuance of securities by Southern Power Company is subject to regulatory approval by the FERC. Additionally, with respect to the public offering of securities, Southern Power Company files registration statements with the SEC under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the FERC, as well as the amounts registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

As of December 31, 2014, the Company's current liabilities exceeded current assets by $320.1 million due to the long-term debt maturing in 2015 and the use of short-term debt as a funding source, as well as cash needs, which can fluctuate significantly due to the seasonality of the business. In 2015, the Company expects to utilize the capital markets and commercial paper markets as the source of funds for the majority of its maturities.
To meet liquidity and capital resource requirements, the Company had at December 31, 2014 cash and cash equivalents of approximately $74.6 million and Southern Power Company had a committed credit facility of $500 million (Facility) expiring in

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2018. As of December 31, 2014, the total amount available under the Facility was $488 million. The Facility does not contain a material adverse change clause applicable to borrowing. Subject to applicable market conditions, Southern Power Company plans to renew the Facility prior to its expiration.
The Facility contains a covenant that limits the ratio of debt to capitalization (each as defined in the Facility) to a maximum of 65% and contains a cross default provision that is restricted only to indebtedness of the Company. Southern Power Company is currently in compliance with all covenants in the Facility.
Proceeds from the Facility may be used for working capital and general corporate purposes as well as liquidity support for the Company's commercial paper program. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.
The Company's commercial paper program is used to finance acquisition and construction costs related to electric generating facilities and for general corporate purposes.
Details of short-term borrowings were as follows:

	Commercial Paper at the End of the Period		Commercial Paper During the Period [a]		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		(in millions)		(in millions)
December 31, 2014	$195	0.4%	$54	0.4%	$445
December 31, 2013	$—	N/A	$117	0.4%	$271
December 31, 2012	$71	0.5%	$170	0.5%	$309

(a) Average and maximum amounts are based upon daily balances during the twelve-month periods ended December 31, 2014, 2013, and 2012.

The Company believes the need for working capital can be adequately met by utilizing the commercial paper program, the Facility, and cash.
Financing Activities
During 2014, the Company prepaid $9.5 million of long-term debt payable to TRE and issued $0.1 million due June 15, 2032, $0.8 million due April 30, 2033, $3.9 million due April 30, 2034, and $5.4 million due May 31, 2034 under promissory notes payable to TRE related to the financing of Apex, Campo Verde, Adobe, and Macho Springs, respectively.
In addition to any financings that may be necessary to meet capital requirements and contractual obligations, Southern Power Company plans to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.
Credit Rating Risk
The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB and Baa2, or BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel transportation and storage, and energy price risk management.
The maximum potential collateral requirements under these contracts at December 31, 2014 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)

At BBB and Baa2	$9
At BBB- and/or Baa3	301
Below BBB- and/or Baa3	1,019

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Included in these amounts are certain agreements that could require collateral in the event that one or more power pool participants has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact the Company's ability to access capital markets, particularly the short-term debt market.

In addition, the Company has a PPA that could require collateral, but not accelerated payment, in the event of a downgrade of Southern Power Company's credit. The PPA requires credit assurances without stating a specific credit rating. The amount of collateral required would depend upon actual losses, if any, resulting from a credit downgrade.

Market Price Risk

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

At December 31, 2014, the Company had $18.8 million of long-term variable rate debt outstanding. The effect on annualized interest expense related to variable interest rate exposure if the Company sustained a 100 basis point change in interest rates is immaterial. Since a significant portion of outstanding indebtedness bears interest at fixed rates, the Company is not aware of any facts or circumstances that would significantly affect exposure on existing indebtedness in the near term. However, the impact on future financing costs cannot be determined at this time.

Because energy from the Company's facilities is primarily sold under long-term PPAs with tolling agreements and provisions shifting substantially all of the responsibility for fuel cost to the counterparties, the Company's exposure to market volatility in commodity fuel prices and prices of electricity is generally limited. However, the Company has been and may continue to be exposed to market volatility in energy-related commodity prices as a result of uncontracted generating capacity.

The changes in fair value of energy-related derivative contracts associated with both power and natural gas positions, none of which are designated as hedges, for the years ended December 31 were as follows:

	2014 Changes	2013 Changes
	Fair Value (in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	$—	$0.8
Contracts realized or settled	0.6	(0.8)
Current period changes[(a)]	1.3	—
Contracts outstanding at the end of the period, assets (liabilities), net	$1.9	$—

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

The changes in contracts outstanding were attributable to both the volume and the prices of power and natural gas as follows:

	December 31, 2014	December 31, 2013
Power – net purchased or (sold)		
MWH (in millions)	(0.5)	0.2
	$11.32	$(2.22)

Weighted average contract cost per MWH above (below) market prices (in dollars)		
Natural gas net purchased		
Commodity – mmBtu	3.4	1.6
Commodity – weighted average contract cost per mmBtu above (below) market prices (in dollars)	$1.02	$(0.08)

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At December 31, 2014, the net fair value of energy-related derivative contracts that were not designated as hedging instruments was $1.9 million. For the Company'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 not material for any year presented. This third party hedging activity was discontinued prior to the end of 2014.

Gains and losses on energy-related derivatives designated as cash flow hedges which are used by the Company to hedge anticipated purchases and sales are initially deferred in OCI before being recognized in income in the same period as the hedged transactions are reflected in earnings. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

The Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. See Note 8 to the financial statements for further discussion of fair value measurements. The maturities of the energy-related derivative contracts, which are all Level 2 of the fair value hierarchy, at December 31, 2014 were as follows:

	Fair Value Measurements December 31, 2014			
	Total	Maturity		
	Fair Value	Year 1	Years 2&3	Years 4&5
	(in millions)			
Level 1	$—	$—	$—	$—
Level 2	1.9	1.9	—	—
Level 3	—	—	—	—
Fair value of contracts outstanding at end of period	$1.9	$1.9	$—	$—

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by S&P and Moody's or with counterparties who have posted collateral to cover potential credit exposure. The Company has also established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk. Therefore, the Company does not anticipate a material adverse effect on the financial statements as a result of counterparty nonperformance. See Note 1 to the financial statements under "Financial Instruments" and Note 9 to the financial statements for additional information.

Capital Requirements and Contractual Obligations

The capital program of the Company is currently estimated to be $1.4 billion for 2015, $1.3 billion for 2016, and $407.0 million for 2017. The construction program is subject to periodic review and revision. These amounts include estimates for potential plant acquisitions and new construction. In addition, the construction program includes capital improvements and work to be performed under LTSAs. Planned expenditures for plant acquisitions may vary materially due to market opportunities and the Company's ability to execute its growth strategy. Actual construction costs may vary from these estimates because of changes in factors such as: business conditions; environmental statutes and regulations; FERC rules and regulations; load projections; legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; and the cost of capital.

In addition, pursuant to an agreement with TRE, on or after November 25, 2015, or earlier in the event of the death of the controlling member of TRE, TRE may require the Company to purchase its noncontrolling interest in STR at fair market value.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, leases, derivative obligations, and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 1, 5, 6, 7, and 9 to the financial statements for additional information.

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Contractual Obligations

	2015	2016-2017	2018-2019	After 2019	Total
	(in millions)				
Long-term debt[(a)] —					
Principal	$525.3	$—	$—	$1,093.8	$1,619.1
Interest	72.5	117.4	117.4	1,238.1	1,545.4
Financial derivative obligations[(b)]	3.5	0.1	—	—	3.6
Operating leases[(c)]	4.5	9.1	9.3	157.2	180.1
Unrecognized tax benefits[(d)]	4.7	—	—	—	4.7
Purchase commitments —					
Capital[(e)]	1,306.0	1,546.0	—	—	2,852.0
Fuel[(f)]	367.2	625.0	572.4	183.2	1,747.8
Purchased power[(g)]	53.5	77.4	80.5	83.8	295.2
Other[(h)]	52.9	226.7	158.8	560.4	998.8
Transmission agreements[(i)]	7.9	15.0	6.8	—	29.7
Total	$2,398.0	$2,616.7	$945.2	$3,316.5	$9,276.4

(a) All amounts are reflected based on final maturity dates. The Company plans to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.
(b) For additional information, see Notes 1 and 9 to the financial statements.
(c) Operating lease commitments for the Plant Stanton Unit A land lease are subject to annual price escalation based on the Consumer Price Index for All Urban Consumers.
(d) See Note 5 to the financial statements under "Unrecognized Tax Benefits" for additional information.
(e) The Company provides estimated capital expenditures for a three year period. Amounts represent current estimates of total expenditures, excluding capital expenditures covered under LTSAs. See Note (h) below.
(f) Primarily includes commitments to purchase, transport, and store natural gas fuel. Amounts reflected are based on contracted cost and may contain provisions for price escalation. Amounts reflected for natural gas purchase commitments are based on various indices at the time of delivery and have been estimated based on the New York Mercantile Exchange future prices at December 31, 2014.
(g) Purchased power commitments of $37.6 million in 2015, $77.4 million in 2016-2017, $80.5 million in 2018-2019, and $83.8 million after 2019 will be resold under a third party agreement at cost.
(h) Includes LTSAs, capital leases, and operation and maintenance agreements. LTSAs include price escalation based on inflation indices.
(i) Transmission commitments are based on Southern Company's current tariff rate for point-to-point transmission.

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Cautionary Statement Regarding Forward-Looking Statements

The Company's 2014 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning the strategic goals for the Company's business, customer growth, economic recovery, fuel and environmental cost recovery, current and proposed environmental regulations and related compliance plans and estimated expenditures, access to sources of capital, financing activities, estimated sales and purchases under power sale and purchase agreements, timing of expected future capacity need in existing markets, completion of acquisitions and construction projects, filings with federal regulatory authorities, and estimated construction and other plans and expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, environmental laws including regulation of water and emissions of sulfur, nitrogen, CO_2, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, and also changes in tax and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including IRS and state tax audits;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the last recession, population and business growth (and declines), the effects of energy conservation and efficiency measures, including from the development and deployment of alternative energy sources such as self-generation and distributed generation technologies, and any potential economic impacts resulting from federal fiscal decisions;
- available sources and costs of fuels;
- effects of inflation;
- the ability to control costs and avoid cost overruns during the development and construction of generating facilities, to construct facilities in accordance with the requirements of permits and licenses, and to satisfy any operational and environmental performance standards, including the requirements of tax credits and other incentives;
- advances in technology;
- state and federal rate regulations;
- the ability to successfully operate generating facilities and the successful performance of necessary corporate functions;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Company's business resulting from cyber intrusion or terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and financial market conditions and the results of financing efforts;
- changes in the Company's credit ratings, including impacts on interest rates, access to capital markets, and collateral requirements;
- the impacts of any sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on currency exchange rates, counterparty performance, and the economy in general;
- the ability of the Company to obtain additional generating capacity at competitive prices;

- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes and other storms, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and

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- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

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

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CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2014, 2013, and 2012
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	2014	2013	2012
	(in thousands)		
Operating Revenues:			
Wholesale revenues, non-affiliates	$1,115,880	$922,811	$753,653
Wholesale revenues, affiliates	382,523	345,799	425,180
Other revenues	2,846	6,616	7,215
Total operating revenues	1,501,249	1,275,226	1,186,048
Operating Expenses:			
Fuel	596,319	473,805	426,257
Purchased power, non-affiliates	104,871	75,954	80,438
Purchased power, affiliates	66,033	30,415	12,915
Other operations and maintenance	237,061	208,366	173,074
Depreciation and amortization	220,174	175,295	142,624
Taxes other than income taxes	21,512	21,416	19,309
Total operating expenses	1,245,970	985,251	854,617
Operating Income	255,279	289,975	331,431
Other Income and (Expense):			
Interest expense, net of amounts capitalized	(88,992)	(74,475)	(62,503)
Other income (expense), net	5,560	(4,072)	(1,022)
Total other income and (expense)	(83,432)	(78,547)	(63,525)
Earnings Before Income Taxes	171,847	211,428	267,906
Income taxes (benefit)	(3,228)	45,895	92,621
Net Income	175,075	165,533	175,285
Less: Net income attributable to noncontrolling interests	2,775	—	—
Net Income Attributable to Southern Power Company	$172,300	$165,533	$175,285

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

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CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2014, 2013, and 2012
Southern Power Company and Subsidiary Companies 2014 Annual Report

	2014	2013	2012
	(in thousands)		
Net Income	$175,075	$165,533	$175,285
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $-, $-, and $(90), respectively	—	—	(136)
Reclassification adjustment for amounts included in net income, net of tax of $169, $2,357, and $3,919, respectively	367	3,695	6,189
Total other comprehensive income	367	3,695	6,053
Less: Comprehensive income attributable to noncontrolling interests	2,775	—	—
Comprehensive Income Attributable to Southern Power Company	$172,667	$169,228	$181,338

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

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CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2014, 2013, and 2012
Southern Power Company and Subsidiary Companies 2014 Annual Report

	2014	2013	2012
	(in thousands)		
Operating Activities:			
Net income	$175,075	$165,533	$175,285
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization	225,234	183,239	156,268
Deferred income taxes	(168,110)	171,301	228,780
Investment tax credits	73,512	158,096	45,047
Amortization of investment tax credits	(11,399)	(5,535)	(2,633)
Deferred revenues	(20,860)	(18,477)	(12,633)
Mark-to-market adjustments	(1,894)	850	(9,275)
Other, net	11,629	3,335	3,104
Changes in certain current assets and liabilities —			
-Receivables	(25,596)	(11,178)	(1,384)
-Fossil fuel stock	(2,576)	2,438	(8,578)
-Materials and supplies	(3,613)	(8,410)	(7,825)
-Prepaid income taxes	35,284	(29,609)	(3,223)
-Other current assets	(1,822)	(2,219)	(1,624)
-Accounts payable	30,352	(11,572)	10,514
-Accrued taxes	284,348	(299)	431
-Accrued interest	1,166	6,093	385
-Other current liabilities	1,646	777	492
Net cash provided from operating activities	602,376	604,363	573,131
Investing Activities:			
Property additions	(20,566)	(500,756)	(116,633)
Cash paid for acquisitions	(730,509)	(132,163)	(124,059)
Change in construction payables	(279)	(4,072)	(27,387)
Payments pursuant to long-term service agreements	(60,554)	(57,269)	(63,932)
Other investing activities	(1,756)	(1,725)	(446)
Net cash used for investing activities	(813,664)	(695,985)	(332,457)
Financing Activities:			
Increase (decrease) in notes payable, net	194,917	(70,968)	(108,552)
Proceeds —			
Capital contributions	146,356	1,487	(662)
Senior notes	—	300,000	—
Other long-term debt	10,253	23,583	5,470
Redemptions — Other long-term debt	(9,513)	(9,284)	(2,450)
Distributions to noncontrolling interests	(1,089)	(506)	—
Capital contributions from noncontrolling interests	7,531	17,328	3,400
Payment of common stock dividends	(131,120)	(129,120)	(127,000)
Other financing activities	(185)	(746)	769
Net cash provided from (used for) financing activities	217,150	131,774	(229,025)
Net Change in Cash and Cash Equivalents	5,862	40,152	11,649
Cash and Cash Equivalents at Beginning of Year	68,744	28,592	16,943

Cash and Cash Equivalents at End of Year	$74,606	$68,744	$28,592
Supplemental Cash Flow Information:			
Cash paid (received) during the period for —			
Interest (net of $(113), $9,178 and $19,092 capitalized, respectively)	$85,168	$60,396	$50,248
Income taxes (net of refunds and investment tax credits)	(219,641)	(226,179)	(175,269)
Noncash transactions —			
Accrued property additions at year-end	852	5,567	11,203
Acquisitions	228,964	—	—
Capital contributions from noncontrolling interests	220,734	—	—

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

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CONSOLIDATED BALANCE SHEETS
At December 31, 2014 and 2013
Southern Power Company and Subsidiary Companies 2014 Annual Report

Assets	2014	2013
	(in thousands)	
Current Assets:		
Cash and cash equivalents	$74,606	$68,744
Receivables —		
Customer accounts receivable	76,608	73,497
Other accounts receivable	14,707	3,983
Affiliated companies	34,223	38,391
Fossil fuel stock, at average cost	21,755	19,178
Materials and supplies, at average cost	57,843	54,780
Prepaid income taxes	19,239	54,523
Deferred income taxes, current	305,814	209
Other prepaid expenses	17,301	20,946
Assets from risk management activities	5,297	182
Total current assets	627,393	334,433
Property, Plant, and Equipment:		
In service	5,656,974	4,696,134
Less accumulated provision for depreciation	1,034,610	871,963
Plant in service, net of depreciation	4,622,364	3,824,171
Construction work in progress	10,511	9,843
Total property, plant, and equipment	4,632,875	3,834,014
Other Property and Investments:		
Goodwill	1,839	1,839
Other intangible assets, net of amortization of $8,279 and $5,614 at December 31, 2014 and December 31, 2013, respectively	47,091	43,505
Total other property and investments	48,930	45,344
Deferred Charges and Other Assets:		
Prepaid long-term service agreements	123,573	141,851
Other deferred charges and assets — affiliated	5,492	4,605
Other deferred charges and assets — non-affiliated	111,239	68,853
Total deferred charges and other assets	240,304	215,309
Total Assets	$5,549,502	$4,429,100

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

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CONSOLIDATED BALANCE SHEETS
At December 31, 2014 and 2013
Southern Power Company and Subsidiary Companies 2014 Annual Report

Liabilities and Stockholders' Equity	2014	2013
	(in thousands)	
Current Liabilities:		
Securities due within one year	$525,295	$599
Notes Payable	194,917	—
Accounts payable —		
Affiliated	78,279	56,661
Other	30,037	20,747
Accrued taxes —		
Accrued income taxes	71,700	161
Other accrued taxes	2,983	2,662
Accrued interest	29,518	28,352
Other current liabilities	14,761	18,492
Total current liabilities	947,490	127,674
Long-Term Debt:		
Senior notes —		
4.875% due 2015	—	525,000
6.375% due 2036	200,000	200,000
5.15% due 2041	575,000	575,000
5.25% due 2043	300,000	300,000
Other long-term notes (3.25% due 2032-2034)	18,775	17,787
Unamortized debt premium	2,378	2,467
Unamortized debt discount	(813)	(1,013)
Long-term debt	1,095,340	1,619,241
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	862,795	724,390
Investment tax credits	600,519	340,269
Deferred capacity revenues — affiliated	15,279	15,279
Other deferred credits and liabilities — affiliated	604	1,621
Other deferred credits and liabilities — non-affiliated	16,890	7,896
Total deferred credits and other liabilities	1,496,087	1,089,455
Total Liabilities	3,538,917	2,836,370
Redeemable Noncontrolling Interest	39,241	28,778
Common Stockholder's Equity:		
Common stock, par value $0.01 per share —		
Authorized — 1,000,000 shares		
Outstanding — 1,000 shares	—	—
Paid-in capital	1,175,392	1,029,035
Retained earnings	573,178	531,998
Accumulated other comprehensive income	3,286	2,919
Total common stockholder's equity	1,751,856	1,563,952
Noncontrolling Interest	219,488	—
Total Stockholders' Equity	1,971,344	1,563,952
Total Liabilities and Stockholders' Equity	$5,549,502	$4,429,100
Commitments and Contingent Matters (See notes)		

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

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
For the Years Ended December 31, 2014, 2013, and 2012
Southern Power Company and Subsidiary Companies 2014 Annual Report

	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Common Stockholder's Equity	Noncontrolling Interest	Total
	(in thousands)							
Balance at December 31, 2011	1	$—	$1,028,210	$447,301	$(6,829)	$1,468,682	$—	$1,468,682
Net income attributable to Southern Power Company	—	—	—	175,285	—	175,285	—	175,285
Capital contributions from parent company	—	—	(662)	—	—	(662)	—	(662)
Other comprehensive income	—	—	—	—	6,053	6,053	—	6,053
Cash dividends on common stock	—	—	—	(127,000)	—	(127,000)	—	(127,000)
Other	—	—	—	(1)	—	(1)	—	(1)
Balance at December 31, 2012	1	—	1,027,548	495,585	(776)	1,522,357	—	1,522,357
Net income attributable to Southern Power Company	—	—	—	165,533	—	165,533	—	165,533
Capital contributions from parent company	—	—	1,487	—	—	1,487	—	1,487
Other comprehensive income	—	—	—	—	3,695	3,695	—	3,695
Cash dividends on common stock	—	—	—	(129,120)	—	(129,120)	—	(129,120)
Balance at December 31, 2013	1	—	1,029,035	531,998	2,919	1,563,952	—	1,563,952
Net income attributable to Southern Power Company	—	—	—	172,300	—	172,300	—	172,300
	—	—	146,357	—	—	146,357	—	146,357

Capital contributions from parent company								
Other comprehensive income	—	—	—	—	367	367	—	367
Cash dividends on common stock	—	—	—	(131,120)	—	(131,120)	—	(131,120)
Capital contributions from noncontrolling interest	—	—	—	—	—	—	220,734	220,734
Net loss attributable to noncontrolling interest	—	—	—	—	—	—	(1,246)	(1,246)
Balance at December 31, 2014	1	$—	$1,175,392	$573,178	$ 3,286	$ 1,751,856	$ 219,488	$1,971,344

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

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NOTES TO FINANCIAL STATEMENTS
Southern Power Company and Subsidiary Companies 2014 Annual Report

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NOTES (continued)
Southern Power Company and Subsidiary Companies 2014 Annual Report

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES
General
Southern Power Company is a wholly-owned subsidiary of The Southern Company (Southern Company), which is also the parent company of four traditional operating companies, SCS, SouthernLINC Wireless, Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear, and other direct and indirect subsidiaries. The traditional operating companies – Alabama Power, Georgia Power, Gulf Power, and Mississippi Power – are vertically integrated utilities providing electric service in four Southeastern states. Southern Power Company and its subsidiaries (the Company) construct, acquire, own, and manage generation assets, including renewable energy projects, and sell electricity at market-based rates in the wholesale market. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary, primarily for Southern Company's investments in leveraged leases. Southern Nuclear operates and provides services to the Southern Company system's nuclear power plants.
Southern Power Company and certain of its generation subsidiaries are subject to regulation by the FERC. The Company follows GAAP. The preparation of financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates. Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation. This includes an adjustment to the presentation of prepaid long-term service agreements (LTSA) to present amounts as noncurrent assets on the consolidated balance sheets. Prior period amounts recorded within other current assets have been reclassified to conform to the current presentation. See "Long-Term Service Agreements" herein for additional information.
The financial statements include the accounts of Southern Power Company and its wholly-owned subsidiaries, Southern Company – Florida, LLC, Oleander Power Project, LP, and Nacogdoches Power, LLC, which own, operate, and maintain the Company's ownership interests in Plants Stanton Unit A, Oleander, and Nacogdoches, respectively. The financial statements also include the accounts of Southern Power Company's wholly-owned subsidiaries, SRE and SRP. SRE and SRP were formed to construct, acquire, own, and manage renewable generation assets and sell electricity at market-based prices in the wholesale market. Through STR, a jointly-owned subsidiary owned 90% by SRE and 10% by TRE, SRE and its subsidiaries own, operate, and maintain Plants Adobe, Apex, Campo Verde, Cimarron, Granville, Macho Springs, and Spectrum. Through SG2 Holdings, a jointly-owned subsidiary owned 51% by SRP and 49% by First Solar, SRP owns, operates, and maintains Plant Imperial Valley. All intercompany accounts and transactions have been eliminated in consolidation.
Recently Issued Accounting Standards
On May 28, 2014, the Financial Accounting Standards Board issued ASC 606, Revenue from Contracts with Customers. ASC 606 revises the accounting for revenue recognition and is effective for fiscal years beginning after December 15, 2016. The Company continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.
Affiliate Transactions
Southern Power Company has an agreement with SCS under which the following services are rendered to the Company at amounts in compliance with FERC regulation: general and design engineering, purchasing, accounting, finance and treasury, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, labor, and other services with respect to business and operations, construction management, and transactions associated with the Southern Company system's fleet of generating units. Because the Company has no employees, all employee-related charges are rendered at amounts in compliance with FERC regulation under agreements with SCS. Costs for all of these services from SCS amounted to approximately $125.9 million in 2014, $117.6 million in 2013, and $125.4 million in 2012. Of these costs, approximately $124.8 million in 2014, $114.3 million in 2013, and $107.7 million in 2012 were other operations and

maintenance expenses; the remainder was recorded to plant in service. Cost allocation methodologies used by SCS prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, were approved by the SEC. Subsequently, additional cost allocation methodologies have been reported to the FERC and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies.

The Company has several agreements with SCS for transmission services. Transmission purchased from affiliates totaled $6.8 million in 2014, $8.3 million in 2013, and $6.6 million in 2012. All charges were billed to the Company based on the Southern Company Open Access Transmission Tariff as filed with the FERC.

NOTES (continued)
Southern Power Company and Subsidiary Companies 2014 Annual Report

Total billings for all PPAs with affiliates were $156.4 million, $148.4 million, and $159.9 million in 2014, 2013, and 2012, respectively. Deferred amounts outstanding as of December 31 are included in the balance sheet as follows:

	2014		2013	
	(in millions)			
Other deferred charges and assets - affiliated	$ 2.9		$ 1.9	
Other current liabilities	—		(4.2	)
Deferred capacity revenues - affiliated	(15.3	)	(15.3	)
Total deferred amounts outstanding	$ (12.4	)	$ (17.6	)

Revenue recognized under affiliate PPAs accounted for as operating leases totaled $74.8 million, $69.0 million, and $76.2 million in 2014, 2013, and 2012, respectively. The Company and the traditional operating companies may jointly enter into various types of wholesale energy, natural gas, and certain other contracts, either directly or through SCS as agent. Each participating company may be jointly and severally liable for the obligations incurred under these agreements. See "Revenues" herein for additional information.

The Company and the traditional operating companies generally settle amounts related to the above transactions on a monthly basis in the month following the performance of such services or the purchase or sale of electricity.

Acquisition Accounting

The Company acquires generation assets as part of its overall growth strategy. The Company accounts for business acquisitions from non-affiliates as business combinations. Accordingly, the Company includes these operations in the consolidated financial statements from the respective date of acquisition. The purchase price, including contingent consideration, if any, of each acquisition is 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 is allocated based on the relative fair value of assets acquired. Any due diligence or transition costs incurred by the Company for successful or potential acquisitions are expensed as incurred.

Revenues

The Company sells capacity at rates specified under contractual terms for long-term PPAs. These PPAs are generally accounted for as operating leases, non-derivatives, or normal sale derivatives. Capacity revenues from PPAs classified as operating leases are recognized on a straight-line basis over the term of the agreement. Capacity revenues from PPAs classified as non-derivatives or normal sales are recognized at the lesser of the levelized amount or the amount billable under the contract over the respective contract periods. When multiple contracts exist with the same counterparty, the revenues from each contract are accounted for as separate arrangements.

The Company may also enter into contracts to sell short-term capacity in the wholesale electricity markets. These sales are generally classified as mark-to-market derivatives and net unrealized gains (losses) on such contracts are recorded in wholesale revenues. See Note 9 for further information.

Energy revenues and other contingent revenues are recognized in the period the energy is delivered or the service is rendered. All revenues under solar PPAs are accounted for as contingent revenues and recognized as services are performed. Transmission revenues and other fees are recognized as earned as other operating revenues. Revenues are recorded on a gross basis for all full requirements PPAs. See "Financial Instruments" herein for additional information.

Significant portions of the Company's revenues have been derived from certain customers pursuant to PPAs. The following table shows the percentage of total revenues for the top three customers:

	2014		2013		2012	
FPL	10.1	%	11.8	%	12.8	%
Georgia Power	9.7	%	10.7	%	12.5	%
Duke Energy Corporation	9.1	%	10.3	%	5.9	%

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NOTES (continued)
Southern Power Company and Subsidiary Companies 2014 Annual Report

Fuel Costs
Fuel costs are expensed as the fuel is used. Fuel costs also include emissions allowances which are expensed as the emissions occur.
Income and Other Taxes
The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences.
Under the American Recovery and Reinvestment Act of 2009 (ARRA), and the American Taxpayer Relief Act of 2012 (ATRA), certain projects are eligible for federal 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 $11.4 million, $5.5 million, and $2.6 million in 2014, 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. The Company has elected to recognize the tax benefit of this basis difference as a reduction to income tax expense in the year in which the plant reaches commercial operation. Federal and state ITCs available to reduce income taxes payable were not fully utilized during the year and will be carried forward and utilized in future years. See Note 5 under "Effective Tax Rate" for additional information.
In accordance with accounting standards related to the uncertainty in income taxes, the Company recognizes tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 5 under "Unrecognized Tax Benefits" for additional information.
Property, Plant, and Equipment
The Company's depreciable property, plant, and equipment consists entirely of generation assets.
Property, plant, and equipment is stated at original cost. Original cost includes: materials, direct labor incurred by contractors and affiliated companies, minor items of property, and interest capitalized. Interest is capitalized on qualifying projects during the development and construction period. The cost to replace significant items of property defined as retirement units is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to other operations and maintenance expenses as incurred.
Depreciation
Beginning in 2014, the Company changed to component depreciation, where the depreciation of the original cost of assets is computed principally by the straight-line method over the estimated useful lives of assets as determined by management. Certain generation assets are now depreciated on a units-of-production basis, using hours or starts, to better match outage and maintenance costs to the usage of and revenues from these assets. The primary assets in property, plant, and equipment are power plants, which have estimated useful lives ranging from 35 to 45 years. The Company reviews its estimated useful lives and salvage values on an ongoing basis. The results of these reviews could result in changes which could have a material impact on net income in the near term. The book value of plant-in-service as of December 31, 2014 that is depreciated on a units-of-production basis was approximately $470.2 million.
When property subject to depreciation is retired or otherwise disposed of in the normal course of business, the applicable cost and accumulated depreciation is removed from the accounts and a gain or loss is recognized. For other property dispositions, the applicable cost and accumulated depreciation is removed from the balance sheet accounts and a gain or loss is recognized.
Prior to 2014, the Company computed depreciation of the original cost of assets under the straight-line method and applied a composite depreciation rate based on the assets' estimated useful lives as determined by management.
Long-Term Service Agreements
The Company has entered into LTSAs for the purpose of securing maintenance support for substantially all of its generating facilities. The LTSAs cover all planned inspections on the covered equipment, which generally includes the cost of all labor and materials. The LTSAs also obligate the counterparties to cover the costs of unplanned maintenance on the covered equipment subject to limits and scope specified in each contract.

Payments made under the LTSAs prior to the performance of any planned inspections or unplanned capital maintenance are recorded as a prepayment in noncurrent assets on the balance sheets and are recorded as payments pursuant to LTSAs in the statements of cash flows. All work performed is capitalized or charged to expense as appropriate based on the nature of the work when performed; therefore, these charges are non-cash and are not reflected in the statements of cash flows.

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Southern Power Company and Subsidiary Companies 2014 Annual Report

Impairment of Long-Lived Assets and Intangibles
The Company evaluates long-lived assets and finite-lived intangibles for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The Company's intangible assets consist of acquired PPAs that are amortized over the term of the PPA and goodwill resulting from acquisitions. The average term of these PPAs is 20 years. The determination of whether an impairment has occurred is based on an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If the estimate of undiscounted future cash flows is less than the carrying value of the asset, the fair value of the asset is determined and a loss is recorded. For assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell in order to determine if an impairment loss is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change.
The amortization expense for the acquired PPAs for the years ended December 31, 2014, 2013, and 2012 was $2.5 million, $2.5 million, and $1.7 million, respectively, and the amortization for future periods is as follows:

	Amortization Expense (in millions)
2015	$2.5
2016	2.4
2017	2.5
2018	2.5
2019	2.5
2020 and beyond	28.5
Total	$40.9

Emission Reduction Credits
The Company has acquired emission reduction credits necessary for future unspecified construction in areas designated by the EPA as non-attainment areas for nitrogen oxide or volatile organic compound emissions. These credits are reflected on the balance sheets at historical cost. The cost of emission reduction offsets to be surrendered are generally transferred to CWIP upon commencement of construction. The total emission reduction credits were $11.0 million at December 31, 2014 and 2013.
Cash and Cash Equivalents
For purposes of the financial statements, temporary cash investments are considered cash equivalents. Temporary cash investments are securities with original maturities of 90 days or less.
Materials and Supplies
Generally, materials and supplies include the average cost of generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when installed.
Fuel Inventory
Fuel inventory includes the cost of oil, natural gas, biomass, and emissions allowances. The Company maintains oil inventory for use at several generating units. The Company has contracts in place for natural gas storage to support normal operations of the Company's natural gas generating units. The Company maintains biomass inventory for use at Plant Nacogdoches. Inventory is maintained using the weighted average cost method. Fuel inventory and emissions allowances are recorded at actual cost when purchased and then expensed at weighted average cost as used. Emissions allowances granted by the EPA are included at zero cost.
Financial Instruments
The Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, and electricity purchases and sales. All derivative financial instruments are recognized as either assets or liabilities (included in "Other" or shown separately as "Risk Management Activities") and are measured at

fair value. See Note 8 for additional information regarding fair value. Substantially all of the Company's bulk energy purchases and sales contracts that meet the definition of a derivative are excluded from fair value accounting requirements because they qualify for the "normal" scope exception, and are accounted for under the accrual method. Derivative contracts that qualify as cash flow hedges of

NOTES (continued)
Southern Power Company and Subsidiary Companies 2014 Annual Report

anticipated transactions result in the deferral of related gains and losses in AOCI until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts that qualify as fair value hedges are marked to market through current period income and are recorded in the financial statement line item where they will eventually settle. See Note 9 for additional information regarding derivatives.
Cash flows from derivatives are classified on the statement of cash flows in the same category as the hedged item.
The Company does not offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. Additionally, the Company had no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2014.
The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company has established controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk.

Comprehensive Income

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners.
Comprehensive income consists of net income, changes in the fair value of qualifying cash flow hedges, and reclassifications of amounts included in net income.

Variable Interest Entities

The primary beneficiary of a variable interest entity (VIE) is required to consolidate the VIE when it has both the power to direct the activities of the VIE that most significantly impact the VIE's economic performance and the obligation to absorb losses or the right to receive benefits from the VIE that could potentially be significant to the VIE.
The Company has certain wholly-owned subsidiaries that are determined to be VIEs. The Company is considered the primary beneficiary of these VIEs because it controls the most significant activities of the VIEs, including operating and maintaining the respective assets, and has the obligation to absorb expected losses of these VIEs to the extent of its equity interests.

2. ACQUISITIONS

2014

Adobe Solar, LLC

On April 17, 2014, the Company and TRE, through STR, a jointly-owned subsidiary owned 90% by the Company, acquired all of the outstanding membership interests of Adobe from Sun Edison, LLC, the original developer of the project. Adobe constructed and owns an approximately 20-MW solar generating facility in Kern County, California. The solar facility began commercial operation on May 21, 2014 and the entire output of the plant is contracted under a 20-year PPA with SCE. The acquisition was in accordance with the Company's overall growth strategy.
The Company's acquisition of Adobe included cash consideration of approximately $96.2 million, which included TRE's 10% equity contribution. The fair values of the assets, liabilities, and intangibles acquired were recorded as follows: $83.5 million to property, plant, and equipment, $14.5 million to prepayment related to transmission services, and $6.3 million to PPA intangible, resulting in a $5.2 million bargain purchase gain with a $2.9 million deferred tax liability. The bargain purchase gain is included in other income (expense), net in the Company's Statements of Income herein. Acquisition-related costs were expensed as incurred and were not material.

Macho Springs Solar, LLC

On May 22, 2014, the Company and TRE, through STR, acquired all of the outstanding membership interests of Macho Springs from First Solar Development, LLC, the original developer of the project. Macho Springs constructed and owns an approximately 50-MW solar photovoltaic facility in Luna County, New Mexico. The solar facility began commercial operation on May 23, 2014 and the entire output of the plant is contracted under a 20-year PPA with EPE. The acquisition was in accordance with the Company's overall growth strategy.

The Company's acquisition of Macho Springs included cash consideration of approximately $130.0 million, which included TRE's 10% equity contribution. The fair values of the assets acquired were recorded as follows: $128.0 million to property, plant, and equipment, $1.0 million to prepaid property taxes, and $1.0 million to prepayment related to transmission services. The acquisition did not include any contingent consideration. Acquisition-related costs were expensed as incurred and were not material.

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SG2 Imperial Valley, LLC

On October 22, 2014, the Company, through its subsidiaries SRP and SG2 Holdings, acquired all of the outstanding membership interests of Imperial Valley from a wholly-owned subsidiary of First Solar, the developer of the project. Imperial Valley constructed and owns an approximately 150-MW solar photovoltaic facility in Southern California. The solar facility began commercial operation on November 26, 2014 and at that time a subsidiary of First Solar was admitted as a minority member of SG2 Holdings. The entire output of the plant is contracted under a 25-year PPA with San Diego Gas & Electric Company, a subsidiary of Sempra Energy (SDG&E). The acquisition was in accordance with the Company's overall growth strategy.

In connection with this acquisition, SG2 Holdings made an aggregate payment of approximately $127.9 million to a subsidiary of First Solar and became obligated to pay additional contingent consideration of approximately $599.3 million upon completion of the facility (representing the amount due to an affiliate of First Solar under the construction contract for Imperial Valley). When substantial completion was achieved on November 26, 2014, a subsidiary of First Solar was admitted as a minority member of SG2 Holdings. The members of SG2 Holdings made additional agreed upon capital contributions totaling $593.3 million to SG2 Holdings that were used to pay the contingent consideration due, leaving $6.0 million of contingent consideration payable upon final acceptance of the facility. As a result of these capital contributions, the aggregate purchase price payable by the Company for the acquisition of Imperial Valley was approximately $504.7 million in addition to the $222.5 million noncash contribution by the minority member. Following these capital contributions, the Company indirectly owns 100% of the class A membership interests of SG2 Holdings and is entitled to 51% of all cash distributions from SG2 Holdings, and First Solar indirectly owns 100% of the class B membership interests of SG2 Holdings and is entitled to 49% of all cash distributions from SG2 Holdings. In addition, the Company is entitled to substantially all of the federal tax benefits with respect to this transaction. As of December 31, 2014, the fair values of the assets acquired were recorded as follows: $707.5 million to property, plant, and equipment and $19.7 million to prepayment related to transmission services; however, the allocation of the purchase price to individual assets has not been finalized. Acquisition-related costs were expensed as incurred and were not material.

2013

Campo Verde Solar, LLC

In April 2013, the Company and TRE, through STR, acquired all of the outstanding membership interests of Campo Verde from First Solar, the developer of the project. Campo Verde constructed and owns an approximately 139-MW solar photovoltaic facility in Southern California. The solar facility began commercial operation in October 2013 and the entire output of the plant is contracted under a 20-year PPA with SDG&E. The asset acquisition was in accordance with the Company's overall growth strategy.

The Company's acquisition of Campo Verde included cash consideration of $136.6 million, which included TRE's 10% equity contribution. The fair value of the assets acquired was allocated entirely to property, plant, and equipment. The acquisition did not include any contingent consideration and due diligence costs were expensed as incurred and were not material. Under an engineering, procurement, and construction agreement, an additional $355.5 million was paid to a subsidiary of First Solar for construction of the solar facility.

Subsequent Events

Decatur County Solar Projects

On February 19, 2015, the Company acquired all of the outstanding membership interests of Decatur Parkway Solar Project, LLC and Decatur County Solar Project, LLC from TradeWind Energy, Inc. as part of the Company's plans to build two solar photovoltaic facilities; the Decatur Parkway Solar Project and the Decatur County Solar Project. These two projects, approximately 80-MW and 19-MW, respectively, will be constructed on separate sites in Decatur County, Georgia. The construction of the Decatur Parkway Solar Project commenced in February 2015 while the construction of the Decatur County Solar Project is expected to commence in June 2015. Both projects are expected to begin commercial operation in late 2015, and the entire output of each project is contracted to Georgia Power. The entire output of the Decatur Parkway Solar Project is contracted under a 25-year PPA with Georgia Power and the entire output of the Decatur County Solar Project is contracted under a separate 20-year PPA with Georgia Power. The total estimated cost of the facilities is expected to be between $200 million and $220 million, which includes the acquisition price for all of the outstanding membership interests of Decatur Parkway Solar Project, LLC and Decatur County Solar Project, LLC from TradeWind Energy, Inc. The acquisition is in accordance with the Company's overall growth strategy.

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Kay County Wind Facility
On February 24, 2015, the Company, through its wholly-owned subsidiary SRE, entered into a purchase agreement with Kay Wind Holdings, LLC, a wholly-owned subsidiary of Apex Clean Energy Holdings, LLC, the developer of the project, to acquire all of the outstanding membership interests of Kay Wind. Kay Wind is constructing an approximately 299-MW wind facility in Kay County, Oklahoma. The wind facility is expected to begin commercial operation in late 2015. The entire output of the facility is contracted under separate 20-year PPAs with Westar Energy, Inc. and Grand River Dam Authority. The acquisition is in accordance with the Company's overall growth strategy. The Company's acquisition of Kay Wind is expected to close in the fourth quarter 2015 and the purchase price is expected to be approximately $492 million, with potential purchase price adjustments based on performance testing. The completion of the acquisition is subject to Kay Wind achieving certain financing, construction, and project milestones, and various customary conditions to closing. The ultimate outcome of this matter cannot be determined at this time.

3. CONTINGENCIES AND REGULATORY MATTERS

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

4. JOINT OWNERSHIP AGREEMENTS

The Company is a 65% owner of Plant Stanton A, a combined-cycle project unit with a nameplate capacity of 659 MWs. The unit is co-owned by the Orlando Utilities Commission (28%), Florida Municipal Power Agency (3.5%), and Kissimmee Utility Authority (3.5%). The Company has a service agreement with SCS whereby SCS is responsible for the operation and maintenance of Plant Stanton A. As of December 31, 2014, $156.5 million was recorded in plant in service with associated accumulated depreciation of $46.6 million. These amounts represent the Company's share of the total plant assets and each owner is responsible for providing its own financing. The Company's proportionate share of Plant Stanton A's operating expense is included in the corresponding operating expenses in the statements of income.

5. INCOME TAXES

On behalf of the Company, Southern Company files a consolidated federal income tax return and combined state income tax returns for the States of Alabama, Georgia, and Mississippi. In addition, the Company files separate company income tax returns for the States of Florida, New Mexico, South Carolina, and Tennessee. Unitary income tax returns are filed 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.

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

	2014	2013	2012
	(in millions)		
Federal —			
Current	$178.6	$(120.2)	$(133.1)
Deferred	(166.0)	158.7	210.4
	12.6	38.5	77.3
State —			
Current	(13.8)	(5.2)	(3.0)
Deferred	(2.0)	12.6	18.3
	(15.8)	7.4	15.3
Total	$(3.2)	$45.9	$92.6

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:

	2014	2013
	(in millions)	
Deferred tax liabilities —		
Accelerated depreciation and other property basis differences	$1,006.5	$829.5
Basis difference on asset transfers	2.6	2.8
Levelized capacity revenues	17.1	11.2
Other	5.7	0.9
Total	1,031.9	844.4
Deferred tax assets —		
Federal effect of state deferred taxes	28.9	29.7
Net basis difference on federal ITCs	101.5	58.0
Alternative minimum tax carryforward	15.0	1.1
Unrealized tax credits	305.2	—
Unrealized loss on interest rate swaps	6.1	11.2
Levelized capacity revenues	4.9	6.0
Deferred state tax assets	14.5	17.0
Other	4.1	4.7
Total	480.2	127.7
Valuation Allowance	(7.5)	(7.5)
Net deferred income tax assets	472.7	120.2
Total deferred tax liabilities, net	559.2	724.2
Portion included in current assets/(liabilities), net	303.6	0.2
Accumulated deferred income taxes	$862.8	$724.4

Deferred tax liabilities are the result of property related timing differences.
The application of bonus depreciation provisions in current tax law has significantly increased deferred tax liabilities related to accelerated depreciation.
Deferred tax assets consist primarily of timing differences related to net basis differences on federal ITCs and the carryforward of unrealized federal ITCs.

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At December 31, 2014 and December 31, 2013, the Company had state net operating loss (NOL) carryforwards of $246.6 million and $240.8 million, respectively. The NOL carryforwards resulted in deferred tax assets of $9.4 million as of December 31, 2014 and $11.0 million as of December 31, 2013. The Company has established a valuation allowance due to the remote likelihood that the full tax benefits will be realized. During 2014, the estimated amount of NOL utilization decreased resulting in a $15.1 million increase in the valuation allowance. The increase in income tax expense resulting from the higher valuation allowance was offset by the net income impact of a decrease in the deferred tax balance due to a reduction in the state's statutory tax rate.
Of the NOL balance at December 31, 2014, approximately $87.0 million will expire in 2015 and $40.0 million will expire in 2017.
Effective Tax Rate
A reconciliation of the federal statutory income tax rate to the effective income tax rate is as follows:

	2014		2013		2012	
Federal statutory rate	35.0	%	35.0	%	35.0	%
State income tax, net of federal deduction	(6.0	)	2.2		3.7	
Amortization of ITC	(4.3	)	(1.7	)	(1.0	)
ITC basis difference	(27.7	)	(14.5	)	(2.6	)
Other	1.1		0.3		(0.6	)
Effective income tax rate	(1.9	)%	21.3	%	34.5	%

The Company's effective tax rate decreased in 2014 primarily due to increased benefits from federal ITCs related to Plants Adobe, Macho Springs, and Imperial Valley. The Company's effective tax rate decreased in 2013 primarily due to tax benefits from federal ITCs related to Plants Campo Verde and Spectrum.
In 2009, President Obama signed into law the ARRA. Major tax incentives in the ARRA included renewable energy incentives. The ATRA retroactively extended several renewable energy incentives through 2013, including extending federal ITCs for biomass projects which began construction before January 1, 2014.
The Company received cash related to federal ITCs under the renewable energy initiatives of $73.5 million in tax year 2014, $158.1 million in tax year 2013, and $45.0 million in tax year 2012. The tax benefit of the related basis difference reduced income tax expense by $47.5 million in 2014, $31.3 million in 2013, and $7.8 million in 2012. See Note 1 under "Income and Other Taxes" for additional information.
Unrecognized Tax Benefits
Changes during the year in unrecognized tax benefits were as follows:

	2014		2013		2012	
	(in millions)					
Unrecognized tax benefits at beginning of year	$1.5		$2.9		$2.6	
Tax positions increase from current periods	4.7		1.6		0.7	
Tax positions decrease from prior periods	(1.5	)	(3.0	)	(0.2	)
Reductions due to settlements	—		—		(0.2	)
Balance at end of year	$4.7		$1.5		$2.9	

The increase in tax positions from current periods for 2014 and 2013 and the decrease from prior periods in 2014 relates to federal ITCs. The decrease in tax positions from prior periods for 2013 relates to the tax accounting method change for repairs-generation assets. See "Tax Method of Accounting for Repairs" herein for additional information.

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

	2014	2013	2012
	(in millions)		
Tax positions impacting the effective tax rate	$4.7	$1.5	$0.3
Tax positions not impacting the effective tax rate	—	—	2.6
Balance of unrecognized tax benefits	$4.7	$1.5	$2.9

The tax positions impacting the effective tax rate for 2014 and 2013 relate to federal ITCs. The tax positions not impacting the effective tax rate for 2012 related to the tax accounting method change for repairs-generation assets. See "Tax Method of Accounting for Repairs" herein for additional information. These amounts are presented on a gross basis without considering the related federal or state income tax impact.

The Company classifies interest on tax uncertainties as interest expense. Accrued interest for unrecognized tax benefits was immaterial for all periods presented. The Company did not accrue any penalties on uncertain tax positions.

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

The IRS has finalized its audits of Southern Company's consolidated federal income tax returns through 2012. Southern Company has filed its 2013 federal income tax return and has received a partial acceptance letter from the IRS; however, the IRS has not finalized its audit. Southern Company is a participant in the Compliance Assurance Process of the IRS. The audits for the Company's state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2010.

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, in April 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. In September 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 continues to review this guidance; however, these regulations are not expected to have a material impact on the Company's financial statements.

6. FINANCING

Securities Due Within One Year

At December 31, 2014, the Company had $525.0 million of senior notes due within one year. In addition, at December 31, 2014, the Company classified as due within one year approximately $0.3 million of long-term debt payable to TRE that is expected to be repaid in 2015. At December 31, 2013, the Company classified approximately $0.6 million of long-term debt payable to TRE as due within one year.

There are no additional scheduled maturities of long-term debt through 2019.

Other Long-Term Notes

During 2014, the Company prepaid $9.5 million of long-term debt payable to TRE and issued $0.1 million due June 15, 2032, $0.8 million due April 30, 2033, $3.9 million due April 30, 2034, and $5.4 million due May 31, 2034 under promissory notes payable to TRE related to the financing of Apex, Campo Verde, Adobe, and Macho Springs, respectively. At December 31, 2014, and 2013, the Company had $18.8 million and $17.8 million, respectively, of long-term debt payable to TRE.

Senior Notes

During 2013, Southern Power Company issued $300 million aggregate principal amount of its Series 2013A 5.25% Senior Notes due July 15, 2043. The net proceeds from the sale of the Series 2013A Senior Notes were used to repay a portion of its outstanding short-term indebtedness and for other general corporate purposes, including the Company's continuous construction program.

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At December 31, 2014 and 2013, Southern Power Company had $1.6 billion of senior notes outstanding, which included senior notes due within one year.

Bank Credit Arrangements

In February 2013, Southern Power Company amended its $500 million committed credit facility (Facility), which extended the maturity date from 2016 to 2018. As of December 31, 2014, the total amount available under the Facility was $488 million. There were no borrowings outstanding under the Facility at December 31, 2013. The Facility does not contain a material adverse change clause at the time of borrowing. Subject to applicable market conditions, Southern Power Company plans to renew the Facility prior to its expiration.

Southern Power Company is required to pay a commitment fee on the unused balance of the Facility. This fee is less than 1/4 of 1%. The Facility contains a covenant that limits the ratio of debt to capitalization (each as defined in the Facility) to a maximum of 65%. At December 31, 2014, the Company was in compliance with its debt limits.

Proceeds from the Facility may be used for working capital and general corporate purposes as well as liquidity support for the Company's commercial paper program.

The Company's commercial paper program is used to finance acquisition and construction costs related to electric generating facilities and for general corporate purposes. Commercial paper is included in notes payable in the balance sheets.

Details of short-term borrowings are shown below. The Company had no short-term borrowings in 2013.

	Commercial Paper at the End of the Period		
	Amount Outstanding (in millions)	Weighted Average Interest Rate	
December 31, 2014	$195	0.4	%

Dividend Restrictions

Southern Power Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital. The indenture related to certain series of Southern Power Company's senior notes also contains certain limitations on the payment of common stock dividends. No dividends may be paid unless, as of the end of any calendar quarter, the Company's projected cash flows from fixed priced capacity PPAs are at least 80% of total projected cash flows for the next 12 months or the Company's debt to capitalization ratio is no greater than 60%. At December 31, 2014, Southern Power Company was in compliance with these ratios and had no other restrictions on its ability to pay dividends.

7. COMMITMENTS

Fuel Agreements

SCS, as agent for the Company and the traditional operating companies, has entered into various fuel transportation and procurement agreements to supply a portion of the fuel (primarily natural gas) requirements for the operating facilities which are not recognized on the Company's balance sheets. In 2014, 2013, and 2012, the Company incurred fuel expense of $596.3 million, $473.8 million, and $426.3 million, respectively, the majority of which was purchased under long-term commitments. The Company expects that a substantial amount of its future fuel needs will continue to be purchased under long-term commitments.

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and Southern Company's traditional operating companies. Under these agreements, each of the traditional operating companies and the Company may be jointly and severally liable. Southern Company has entered into keep-well agreements with each of the traditional operating companies to ensure they will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of the Company as a contracting party under these agreements.

Operating Leases

The Company has operating lease agreements with various terms and expiration dates. Total rent expense was $4.0 million, $1.9 million, and $0.8 million for 2014, 2013, and 2012, respectively. These amounts include contingent rent expense related to the Plant Stanton Unit A land lease based on escalation in the Consumer Price Index for All Urban Consumers. The Company includes step rents, escalations, and lease concessions in its computation of minimum lease payments, which are recognized on a

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straight-line basis over the minimum lease term. As of December 31, 2014, estimated minimum lease payments under operating leases were $4.5 million in 2015, $4.5 million in 2016, $4.6 million in 2017, $4.6 million in 2018, $4.7 million in 2019, and $157.2 million in 2020 and thereafter. The majority of the committed future expenditures are land leases at solar facilities.

Redeemable Noncontrolling Interest

Pursuant to an agreement with TRE, on or after November 25, 2015, or earlier in the event of the death of the controlling member of TRE, TRE may require the Company to purchase its noncontrolling interest in STR at fair market value.

See Note 10 for additional information.

8. FAIR VALUE MEASUREMENTS

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

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

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, 2014, 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, 2014:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in millions)			
Assets:				
Energy-related derivatives	$—	$5.5	$—	$5.5
Cash equivalents	18.0	—	—	18.0
Total	$18.0	$5.5	$—	$23.5
Liabilities:				
Energy-related derivatives	$—	$3.6	$—	$3.6

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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	$—	$0.6	$—	$0.6
Cash equivalents	68.0	—	—	68.0
Total	$68.0	$0.6	$—	$68.6
Liabilities:				
Energy-related derivatives	$—	$0.6	$—	$0.6

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. See Note 9 for additional information on how these derivatives are used.

As of December 31, 2014 and 2013, 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:

As of December 31, 2014:	Fair Value (in millions)	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
Cash equivalents:				
Money market funds	$18.0	None	Daily	Not applicable
As of December 31, 2013:				
Cash equivalents:				
Money market funds	$68.0	None	Daily	Not applicable

The money market funds are short-term investments of excess funds in various money market mutual funds, which are portfolios of short-term debt securities. The money market funds are regulated by the SEC and typically receive the highest rating from credit rating agencies. Regulatory and rating agency requirements for money market funds include minimum credit ratings and maximum maturities for individual securities and a maximum weighted average portfolio maturity. Redemptions are available on a same day basis up to the full amount of the Company's investment in the money market funds.

As of December 31, 2014 and 2013, other financial instruments for which the carrying amount did not equal fair value were as follows:

	Carrying Amount	Fair Value
	(in millions)	
Long-term debt, including securities due within one year:		
2014	$1,621	$1,785
2013	$1,620	$1,660

The fair values are determined using Level 2 measurements and are based on quoted market prices for the same or similar issues or on the current rates offered to the Company.

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9. DERIVATIVES

The Company is exposed to market risks, primarily commodity price risk and interest rate risk. To manage the volatility attributable to these exposures, the Company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a gross basis. See Note 8 herein for additional information. In the statements of cash flows, the cash impacts of settled energy-related and interest rate derivatives are recorded as operating activities.

Energy-Related Derivatives

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. The Company has limited exposure to market volatility in commodity fuel prices and prices of electricity because its long-term sales contracts shift substantially all fuel cost responsibility to the purchaser. However, the Company has been and may continue to be exposed to market volatility in energy-related commodity prices as a result of uncontracted generating capacity.

To mitigate residual risks relative to movements in electricity prices, the Company enters into physical fixed-price or heat rate contracts for the purchase and sale of electricity through the wholesale electricity market. To mitigate residual risks relative to movements in gas prices, the Company may enter into fixed-price contracts for natural gas purchases; however, a significant portion of contracts are priced at market.

Energy-related derivative contracts are accounted for in one of two methods:

- Cash Flow Hedges – Gains and losses on energy-related derivatives designated as cash flow hedges which are used to hedge anticipated purchases and sales and are initially deferred in 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, 2014, the net volume of energy-related derivative contracts for natural gas positions totaled 3.4 million mmBtu, all of which expire by 2017, which is the longest non-hedge date. At December 31, 2014, the net volume of energy-related derivative contracts for power positions was immaterial. In addition to the volume discussed above, the Company enters into physical natural gas supply contracts that provide the option to sell back excess gas due to operational constraints. The maximum expected volume of natural gas subject to such a feature is 1.0 million mmBtu.

For cash flow hedges, the amounts expected to be reclassified from accumulated OCI to earnings for the next 12-month period ending December 31, 2015 are immaterial.

Interest Rate Derivatives

The Company may also enter into interest rate derivatives from time to time to hedge exposure to changes in interest rates. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges, where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings. The derivatives employed as hedging instruments are structured to minimize ineffectiveness, which is recorded directly to earnings.

At December 31, 2014, there were no interest rate derivatives outstanding.

The estimated pre-tax loss that will be reclassified from AOCI to interest expense for the 12-month period ending December 31, 2015 is $1.0 million. The Company has deferred gains and losses that are expected to be amortized into earnings through 2016.

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Derivative Financial Statement Presentation and Amounts
At December 31, 2014 and 2013, the fair value of energy-related derivatives was reflected in the balance sheets as follows:

Derivative Category	Asset Derivatives Balance Sheet Location	2014	2013	Liability Derivatives Balance Sheet Location	2014	2013
		(in millions)			(in millions)	
Derivatives not designated as hedging instruments						
Energy-related derivatives:	Assets from risk management activities	$5.3	$0.2	Other current liabilities	$3.5	$0.6
	Other deferred charges and assets – non-affiliated	0.2	0.4	Other deferred credits and liabilities – non-affiliated	0.1	—
Total derivatives not designated as hedging instruments		$5.5	$0.6		$3.6	$0.6

The derivative contracts of the Company are not subject to master netting arrangements or similar agreements and are reported gross on the Company's financial statements. Some of these energy-related and interest rate derivative contracts contain certain provisions that permit intra-contract netting of derivative receivables and payables for routine billing and offsets related to events of default and settlements. Amounts related to energy-related derivative contracts at December 31, 2014 and 2013 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	2014	2013	Liabilities	2014	2013
	(in millions)			(in millions)	
Energy-related derivatives presented in the Balance Sheet [(a)]	$5.5	$0.6	Energy-related derivatives presented in the Balance Sheet [(a)]	$3.6	$0.6
Gross amounts not offset in the Balance Sheet [(b)]	(0.1)	(0.1)	Gross amounts not offset in the Balance Sheet [(b)]	(0.1)	(0.1)
Net energy-related derivative assets	$5.4	$0.5	Net energy-related derivative liabilities	$3.5	$0.5

(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.

For the years ended December 31, 2014, 2013, and 2012, the pre-tax effects of energy-related derivatives and interest rate derivatives designated as cash flow hedging instruments on the statements of income were as follows:

Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Reclassified from AOCI into Income (Effective Portion)			
Derivative Category	Statements of Income Location	Amount 2014	2013	2012
		(in millions)		
Energy-related derivatives	Depreciation and amortization	$0.4	$0.4	$0.4
Interest rate derivatives		(0.9)	(6.5)	(10.5)

	Interest expense, net of amounts capitalized			
Total		$(0.5)	$(6.1)	$(10.1)

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

For the Company'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. The pre-tax effects of energy-related derivatives not

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designated as hedging instruments on the Company's statements of income were immaterial for the years ended December 31, 2014, 2013, and 2012. 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 affiliated companies. At December 31, 2014, the amount of collateral posted with its derivative counterparties was immaterial.

At December 31, 2014, the fair value of derivative liabilities with contingent features was $1.5 million. However, because of joint and several liability features underlying these derivatives, the maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $54.5 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.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P or with counterparties who have posted collateral to cover potential credit exposure. The Company has also established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk. Therefore, the Company does not anticipate a material adverse effect on the financial statements as a result of counterparty nonperformance.

10. NONCONTROLLING INTEREST

The following table details the components of redeemable noncontrolling interests for the years ended December 31:

	2014	2013	2012
		(in millions)	
Beginning balance	$ 28.8	$ 8.1	$ 3.8
Net income attributable to redeemable noncontrolling interest	4.0	3.9	0.9
Distributions to redeemable noncontrolling interest	(1.1)	(0.5)	—
Capital contributions from redeemable noncontrolling interest	7.5	17.3	3.4
Ending balance	$ 39.2	$ 28.8	$ 8.1

For the year ended December 31, 2014, net income included in the consolidated statements of changes in stockholders' equity is reconciled to net income presented in the consolidated statements of income as follows:

	2014
Net income attributable to Southern Power Company	$ 172.3
Net loss attributable to noncontrolling interest	(1.2)
Net income attributable to redeemable noncontrolling interest	4.0
Net income	$ 175.1

For the years ended December 31, 2013 and 2012, net income attributable to redeemable noncontrolling interest was $3.9 million and $0.9 million, respectively, and was included in "Other income (expense), net" in the consolidated statements of income.

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11. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)
Summarized quarterly financial information for 2014 and 2013 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income Attributable to Southern Power Company
	(in thousands)		
March 2014	$350,854	$59,358	$33,471
June 2014	328,803	51,073	30,812
September 2014	435,256	104,710	63,631
December 2014	386,336	40,138	44,386
March 2013	$302,947	$64,673	$29,192
June 2013	307,255	55,024	27,922
September 2013	364,767	116,497	85,153
December 2013	300,257	53,781	23,266

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

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	2014	2013	2012	2011	2010
Operating Revenues (in thousands):					
Wholesale — non-affiliates	$1,115,880	$922,811	$753,653	$870,607	$752,772
Wholesale — affiliates	382,523	345,799	425,180	358,585	370,630
Total revenues from sales of electricity	1,498,403	1,268,610	1,178,833	1,229,192	1,123,402
Other revenues	2,846	6,616	7,215	6,769	6,939
Total	$1,501,249	$1,275,226	$1,186,048	$1,235,961	$1,130,341
Net Income Attributable to Southern Power Company (in thousands)	$172,300	$165,533	$175,285	$162,231	$131,309
Cash Dividends on Common Stock (in thousands)	$131,120	$129,120	$127,000	$91,200	$107,100
Return on Average Common Equity (percent)	10.39	10.73	11.72	11.88	10.68
Total Assets (in thousands)	$5,549,502	$4,429,100	$3,779,927	$3,580,977	$3,437,734
Gross Property Additions and Acquisitions (in thousands)	$942,454	$632,919	$240,692	$254,725	$404,644
Capitalization (in thousands):					
Common stock equity	$1,751,856	$1,563,952	$1,522,357	$1,468,682	$1,263,220
Redeemable noncontrolling interest	39,241	28,778	8,069	3,825	—
Noncontrolling interest	219,488	—	—	—	—
Long-term debt	1,095,340	1,619,241	1,306,099	1,302,758	1,302,619
Total (excluding amounts due within one year)	$3,105,925	$3,211,971	$2,836,525	$2,775,265	$2,565,839
Capitalization Ratios (percent):					
Common stock equity	56.4	48.7	53.7	52.9	49.2
Redeemable noncontrolling interest	1.3	0.9	0.3	0.1	—
Noncontrolling interest	7.1	—	—	—	—
Long-term debt	35.2	50.4	46.0	47.0	50.8
Total (excluding amounts due within one year)	100.0	100.0	100.0	100.0	100.0
Kilowatt-Hour Sales (in thousands):					
Wholesale — non-affiliates	19,014,445	15,110,616	15,636,986	16,089,875	13,294,455
Wholesale — affiliates	11,193,530	9,359,500	16,373,245	11,773,890	10,494,339
Total	30,207,975	24,470,116	32,010,231	27,863,765	23,788,794
Average Revenue Per Kilowatt-Hour (cents)	4.96	5.18	3.68	4.41	4.72
Plant Nameplate Capacity Ratings (year-end) (megawatts)*	9,185	8,924	8,764	7,908	7,908
Maximum Peak-Hour Demand (megawatts):					
Winter	3,999	2,685	3,018	3,255	3,295
Summer	3,998	3,271	3,641	3,589	3,543
Annual Load Factor (percent)	51.8	54.2	48.6	51.0	54.0
Plant Availability (percent)**	91.8	91.8	92.9	93.9	94.0
Source of Energy Supply (percent):					
Gas	86.0	88.5	91.0	89.2	88.8
Alternative (Solar and Biomass)	2.9	1.1	0.5	0.2	—
Purchased power —					
From non-affiliates	6.4	6.4	7.2	6.7	5.5
From affiliates	4.7	4.0	1.3	3.9	5.7
Total	100.0	100.0	100.0	100.0	100.0

* Plant nameplate capacity ratings include 100% of all solar facilities. When taking into consideration the Company's 90% equity interest in STR (which includes Plants Adobe, Apex, Campo Verde, Cimarron, Macho Springs and Spectrum) and 51% equity interest in SG2 Holdings (which includes Plant Imperial Valley), the Company's equity portion of total nameplate capacity for 2014 is 9,074 MW.

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

PART III

Items 10, 11, 12 (other than the information under "Code of Ethics" below in Item 10 and in paragraph (b) in Item 12), 13, and 14 for Southern Company are incorporated by reference to Southern Company's Definitive Proxy Statement relating to the 2015 Annual Meeting of Stockholders. Specifically, reference is made to "Nominees for Election as Directors," "Corporate Governance," and "Section 16(a) Beneficial Ownership Reporting Compliance" for Item 10, "Executive Compensation," "Compensation Discussion and Analysis," "Compensation and Management Succession Committee Report," "Compensation Committee Interlocks and Insider Participation," "Compensation Risk Assessment," "Director Compensation," "Director Deferred Compensation Plan," and "Director Compensation Table" for Item 11, "Stock Ownership Table" and "Equity Plan Compensation Information" for Item 12, "Certain Relationships and Related Transactions" and "Director Independence" for Item 13, and "Principal Public Accounting Firm Fees" for Item 14.

Items 10, 11, 12 (other than the information under "Code of Ethics" below in Item 10 and in paragraph (b) in Item 12), 13, and 14 for Alabama Power, Georgia Power, and Mississippi Power are incorporated by reference to the Definitive Information Statements of Alabama Power, Georgia Power, and Mississippi Power relating to each of their respective 2015 Annual Meetings of Shareholders. Specifically, reference is made to "Nominees for Election as Directors," "Corporate Governance," and "Section 16(a) Beneficial Ownership Reporting Compliance" for Item 10, "Executive Compensation," "Compensation Discussion and Analysis," "Compensation and Management Succession Committee Report," "Compensation Committee Interlocks and Insider Participation," "Compensation Risk Assessment," "Director Compensation," "Director Deferred Compensation Plan," and "Director Compensation Table" for Item 11, "Stock Ownership Table" for Item 12, "Certain Relationships and Related Transactions" and "Director Independence" for Item 13, and "Principal Public Accounting Firm Fees" for Item 14.

Items 10, 11, 12, 13, and 14 for Gulf Power are contained herein.

Items 10, 11, 12, and 13 for Southern Power are omitted pursuant to General Instruction I(2)(c) of Form 10-K. Item 14 for Southern Power is contained herein.

PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Identification of directors of Gulf Power (1)

S. W. Connally, Jr. President and Chief Executive Officer Age 45 Served as Director since 2012	Julian B. MacQueen (2) Age 64 Served as Director since 2013
Allan G. Bense (2) Age 63 Served as Director since 2010	J. Mort O'Sullivan, III (2) Age 63 Served as Director since 2010
Deborah H. Calder (2) Age 54 Served as Director since 2010	Michael T. Rehwinkel (2) Age 58 Served as Director since 2013
William C. Cramer, Jr. (2) Age 62 Served as Director since 2002	Winston E. Scott (2) Age 64 Served as Director since 2003

(1) Ages listed are as of December 31, 2014.

(2) No position other than director.

Each of the above is currently a director of Gulf Power, serving a term running from the last annual meeting of Gulf Power's shareholders (June 24, 2014) for one year until the next annual meeting or until a successor is elected and qualified.

There are no arrangements or understandings between any of the individuals listed above and any other person pursuant to which he or she was or is to be selected as a director, other than any arrangements or understandings with directors or officers of Gulf Power acting solely in their capacities as such.

Identification of executive officers of Gulf Power (1)

S. W. Connally, Jr.
President and Chief Executive Officer
Age 45
Served as Executive Officer since 2012

Jim R. Fletcher
Vice President — External Affairs and Corporate Services
Age 48
Served as Executive Officer since 2014

Richard S. Teel
Vice President and Chief Financial Officer
Age 44
Served as Executive Officer since 2010

Michael L. Burroughs
Vice President — Senior Production Officer
Age 54
Served as Executive Officer since 2010

Wendell E. Smith
Vice President — Power Delivery
Age 49
Served as Executive Officer since 2014

Bentina C. Terry
Vice President — Customer Service and Sales
Age 44
Served as Executive Officer since 2007

(1) Ages listed are as of December 31, 2014.

Each of the above is currently an executive officer of Gulf Power, serving a term until the next annual organizational meeting or until a successor is elected and qualified.

There are no arrangements or understandings between any of the individuals listed above and any other person pursuant to which he or she was or is to be selected as an officer, other than any arrangements or understandings with directors or officers of Gulf Power acting solely in their capacities as such.

Identification of certain significant employees. None.

Family relationships. None.

Business experience. Unless noted otherwise, each director has served in his or her present position for at least the past five years.

DIRECTORS

Gulf Power's Board of Directors possesses collective knowledge and experience in accounting, finance, leadership, business operations, risk management, corporate governance, and Gulf Power's industry.

S. W. Connally, Jr. - President and Chief Executive Officer of Gulf Power since July 2012. Mr. Connally has also served as Chairman of Gulf Power's Board of Directors since July 2012. Mr. Connally previously served as Senior Vice President and Chief Production Officer of Georgia Power from July 2010 through June 2012 and Manager of Alabama Power's Plant Barry from August 2007 through July 2010.

Allan G. Bense - Panama City businessman and former Speaker of the Florida House of Representatives. Mr. Bense is a partner in several companies involved in road building, mechanical contracting, insurance, general contracting, golf courses, and farming. Mr. Bense served as Vice Chair of Enterprise Florida, the economic development agency for the state, from January 2009 to January 2011. Mr. Bense is also a member of the board of directors of Capital City Bank Group, Inc.

Deborah H. Calder - Executive Vice President for Navy Federal Credit Union since 2014. From 2008 to 2014, she served as Senior Vice President. Ms. Calder directs the day-to-day operations of more than 4,000 employees and the ongoing construction of Navy Federal Credit Union's campus in the Pensacola area. Ms. Calder has been with Navy Federal Credit Union for over 23 years, serving in previous positions as Vice President of Consumer and Credit Card Lending, Vice President of Collections, Vice President of Call Center Operations, and Assistant Vice President of Credit Cards.

William C. Cramer, Jr. - President and Owner of automobile dealerships in Florida, Georgia, and Alabama.
Mr. Cramer has been an authorized Chevrolet dealer for over 25 years. In 2009, Mr. Cramer became an authorized dealer of Cadillac, Buick, and GMC vehicles.

Julian B. MacQueen - Founder and Chief Executive Officer of Innisfree Hotels, Inc. He is currently a member of the American Hotel & Lodging Association and a director of the Beach Community Bank.
J. Mort O'Sullivan, III - Managing Member of the Warren Averett O'Sullivan Creel division of Warren Averett, LLC, an accounting firm originally formed as O'Sullivan Patton Jacobi in 1981. Mr. O'Sullivan currently focuses on consulting and management advisory services to clients, while continuing to offer his expertise in litigation support, business valuations, and mergers and acquisitions. He is a registered investment advisor.
Michael T. Rehwinkel - Executive Chairman of EVRAZ North America, a steel manufacturer, since July 2013. He previously served as Chief Executive Officer and President of EVRAZ North America from February 2010 to July 2013 and previously

held various executive positions at Georgia-Pacific Corporation. Mr. Rehwinkel is also Chairman of the American Iron and Steel Institute. Mr. Rehwinkel has more than 30 years of industrial business and leadership experience.
Winston E. Scott - Senior Vice President for External Relations and Economic Development, Florida Institute of Technology since March 2012. He previously served as Dean, College of Aeronautics, Florida Institute of Technology, Melbourne, Florida from August 2008 through March 2012. Mr. Scott is also a member of the board of directors of Environmental Tectonics Corporation. Mr. Scott's experience includes serving as a pilot in the U.S. Navy, an astronaut with the National Aeronautic and Space Administration, Executive Director of the Florida Space Authority, and Vice President of Jacobs Engineering.

EXECUTIVE OFFICERS

Michael L. Burroughs - Vice President and Senior Production Officer since August 2010. He previously served as Manager of Georgia Power's Plant Yates from September 2007 to July 2010.
Jim R. Fletcher - Vice President of External Affairs and Corporate Services since March 2014. He previously served as Vice President of Governmental and Regulatory Affairs for Georgia Power from January 2011 to February 2014 and Regulatory Affairs Manager for Georgia Power from March 2006 to January 2011.
Wendell E. Smith - Vice President of Power Delivery since March 2014. He previously served as the General Manager of Distribution Engineering, Construction and Maintenance and Distribution Operations Systems for Georgia Power from January 2012 to February 2014, Transmission Construction Manager for Georgia Power from February 2011 to December 2011, and Distribution Manager for Georgia Power from March 2005 to February 2011.
Richard S. Teel - Vice President and Chief Financial Officer since August 2010. He previously served as Vice President and Chief Financial Officer of Southern Company Generation, a business unit of Southern Company, from January 2007 to July 2010.
Bentina C. Terry - Vice President of Customer Service and Sales since March 2014. She previously served as Vice President of External Affairs and Corporate Services from March 2007 to March 2014.
Involvement in certain legal proceedings. None.
Promoters and Certain Control Persons. None.
Section 16(a) Beneficial Ownership Reporting Compliance. None.

Code of Ethics

The registrants collectively have adopted a code of business conduct and ethics (Code of Ethics) that applies to each director, officer, and employee of the registrants and their subsidiaries. The Code of Ethics can be found on Southern Company's website located at www.southerncompany.com. The Code of Ethics is also available free of charge in print to any shareholder by requesting a copy from Melissa K. Caen, Corporate Secretary, Southern Company, 30 Ivan Allen Jr. Boulevard NW, Atlanta, Georgia 30308. Any amendment to or waiver from the code of ethics that applies to executive officers and directors will be posted on the website.

Corporate Governance

Southern Company has adopted corporate governance guidelines and committee charters. The corporate governance guidelines and the charters of Southern Company's Audit Committee, Compensation and Management Succession Committee, Finance Committee, Governance Committee, and Nuclear/Operations Committee can be found on Southern Company's website located at www.southerncompany.com. The corporate governance guidelines and charters are also available free of charge in print to any shareholder by requesting a copy from Melissa K. Caen, Corporate Secretary, Southern Company, 30 Ivan Allen Jr. Boulevard NW, Atlanta, Georgia 30308.
Southern Company owns all of Gulf Power’s outstanding common stock and Gulf Power has listed only debt securities on the NYSE. Accordingly, under the rules of the NYSE, Gulf Power is exempt from most of the NYSE's listing standards relating to corporate governance. In addition, under the rules of the SEC, Gulf Power is exempt from the audit committee requirements of Section 301 of the Sarbanes-Oxley Act of 2002 and, therefore, is not required to have an audit committee or an audit committee report on whether it has an audit committee financial expert.

Item 11. EXECUTIVE COMPENSATION

GULF POWER

COMPENSATION DISCUSSION AND ANALYSIS (CD&A)
In this CD&A and this Form 10-K, references to the “Compensation Committee” are to the Compensation and Management Succession Committee of the Board of Directors of Southern Company.
This section describes the compensation program for Gulf Power’s Chief Executive Officer and Chief Financial Officer in 2014, as well as each of its other three most highly compensated executive officers serving at the end of the year.

S. W. Connally, Jr.	President and Chief Executive Officer
Richard S. Teel	Vice President and Chief Financial Officer
Michael L. Burroughs	Vice President
Jim R. Fletcher	Vice President
Bentina C. Terry	Vice President

Also described is the compensation of Gulf Power's former Vice President, P. Bernard Jacob, who retired from Gulf Power effective as of May 3, 2014. Collectively, these officers are referred to as the named executive officers.

Executive Summary

Performance and Pay

Performance-based pay represents a substantial portion of the total direct compensation paid or granted to the named executive officers for 2014.

	Salary ($)(1)	% of Total	Short-Term Performance Pay ($)(1)	% of Total	Long-Term Performance Pay ($)(1)	% of Total
S. W. Connally, Jr.	393,907	31%	339,302	27%	517,692	42%
R. S. Teel	252,110	45%	161,989	29%	152,101	26%
M. L. Burroughs	199,209	50%	121,801	30%	80,103	20%
J. R. Fletcher	224,547	49%	149,633	33%	84,480	18%
B. C. Terry	270,543	45%	173,833	29%	163,191	26%

(1) Salary is the actual amount paid in 2014, Short-Term Performance Pay is the actual amount earned in 2014 based on performance, and Long-Term Performance Pay is the value on the grant date of stock options and performance shares granted in 2014. See the Summary Compensation Table for the amounts of all elements of reportable compensation described in this CD&A. Information is provided for named executive officers serving at the end of 2014.

Gulf Power financial and operational and Southern Company earnings per share (EPS) goal results for 2014, as adjusted and further described in this CD&A, are shown below:
Financial: 100% of Target Operational: 149% of Target EPS: 176% of Target

Southern Company’s annualized total shareholder return has been:
1-Year: 25.23% 3-Year: 6.67% 5-year: 13.22%

These levels of achievement resulted in payouts that were aligned with Gulf Power and Southern Company performance.

Compensation and Benefit Beliefs and Practices

The compensation and benefit program is based on the following beliefs:

- Employees’ commitment and performance have a significant impact on achieving business results;
- Compensation and benefits offered must attract, retain, and engage employees and must be financially sustainable;
- Compensation should be consistent with performance: higher pay for higher performance and lower pay for lower performance; and
- Both business drivers and culture should influence the compensation and benefit program.

Based on these beliefs, the Compensation Committee believes that Gulf Power’s executive compensation program should:

- Be competitive with Gulf Power’s industry peers;
- Motivate and reward achievement of Gulf Power’s goals;
- Be aligned with the interests of Southern Company’s stockholders and Gulf Power’s customers; and
- Not encourage excessive risk-taking.

Executive compensation is targeted at the market median of industry peers, but actual compensation is primarily determined by achievement of Gulf Power’s and Southern Company's business goals. Gulf Power believes that focusing on the customer drives achievement of financial objectives and delivery of a premium, risk-adjusted total shareholder return for Southern Company’s stockholders. Therefore, short-term performance pay is based on achievement of Gulf Power’s operational and financial performance goals, with one-third determined by operational performance, such as safety, reliability, and customer satisfaction; one-third determined by business unit financial performance; and one-third determined by Southern Company's EPS performance. Long-term performance pay is tied to Southern Company's stockholder value, with 40% of the target value awarded in Southern Company stock options, which reward stock price appreciation, and 60% awarded in performance shares, which reward Southern Company's total shareholder return performance relative to that of industry peers and stock price appreciation.

Key Governance and Pay Practices

- Annual pay risk assessment required by the Compensation Committee charter.
- Retention by the Compensation Committee of an independent compensation consultant, Pay Governance, that provides no other services to Gulf Power or Southern Company.
- Inclusion of a claw-back provision that permits the Compensation Committee to recoup performance pay from any employee if determined to have been based on erroneous results, and requires recoupment from an executive officer in the event of a material financial restatement due to fraud or misconduct of the executive officer.
- No excise tax gross-up on change-in-control severance arrangements.
- Provision of limited ongoing perquisites with no income tax gross-ups for the President and Chief Executive Officer except on certain relocation-related benefits.
- “No-hedging” provision in Gulf Power’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 Southern Company system executive compensation program. In doing so, the Compensation Committee uses information from others, principally Pay Governance. The Compensation Committee also relies on information from Southern Company's Human Resources staff and, for individual executive officer performance, from Southern Company's and Gulf Power's respective Chief Executive Officers. The role and information provided by each of these sources is described throughout this CD&A.

Consideration of Southern Company Stockholder Advisory Vote on Executive Compensation

The Compensation Committee considered the stockholder vote on Southern Company's executive compensation at the Southern Company 2014 annual meeting of stockholders. In light of the significant support of Southern Company's 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 executive compensation program is competitive, aligned with Gulf Power's and Southern Company's financial and operational performance, and in the best interests of Gulf Power's customers and Southern Company's stockholders.

Executive Compensation Focus

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

- Business unit financial and operational performance and Southern Company EPS, 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).
- Southern Company Common Stock (Common Stock) price changes result in higher or lower ultimate values of stock options.
- Southern Company's total shareholder return compared to those of industry peers leads to higher or lower payouts under the Performance Share Program (performance shares).

In support of this performance-based pay philosophy, Gulf Power has no general employment contracts or guaranteed severance with the named executive officers, except upon a change in control.

The pay-for-performance principles apply not only to the named executive officers, but to hundreds of Gulf Power's employees. The Performance Pay Program covers almost all of the more than 1,300 employees of Gulf Power. Stock options and performance shares were granted to over 125 employees of Gulf Power. These programs engage employees, which ultimately is good not only for them, but also for Gulf Power's customers and Southern Company's stockholders.

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OVERVIEW OF EXECUTIVE COMPENSATION COMPONENTS

The primary components of the 2014 executive compensation program are shown below:

Gulf Power’s executive compensation program consists of a combination of short-term and long-term components. Short-term compensation includes base salary and the Performance Pay Program. Long-term performance-based compensation includes stock options and performance shares. The performance-based compensation components are linked to Gulf Power's financial and operational performance, Common Stock performance, and Southern Company's total shareholder return. The executive compensation program is approved by the Compensation Committee, which consists entirely of independent directors of Southern Company. 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 a competitive market-based compensation level for the Gulf Power Chief Executive Officer. Southern Company's Human Resources staff develops competitive market-based compensation levels for the other Gulf Power named executive officers. The market-based compensation levels for both are developed from a size-appropriate energy services executive compensation survey database. The survey participants, listed below, are utilities with revenues of $1 billion or more. The Compensation Committee reviews the data and uses it in establishing market-based compensation levels for the named executive officers.

AGL Resources Inc.	Entergy Corporation	Pepco Holdings, Inc.
Allete, Inc.	EP Energy Corporation	Pinnacle West Capital Corporation
Alliant Energy Corporation	Eversource International	Portland General Electric Company
Ameren Corporation	Exelon Corporation	PPL Corporation
American Electric Power Company, Inc.	FirstEnergy Corp.	Public Service Enterprise Group Inc.
Areva Inc.	First Solar Inc.	PNM Resources Inc.
Atmos Energy Corporation	GDF SUEZ Energy North America, Inc.	Puget Energy, Inc.
Austin Energy	Iberdrola USA, Inc.	Salt River Project
Avista Corporation	Idaho Power Company	Santee Cooper
Bg US Services, Inc.	Integrys Energy Group, Inc.	SCANA Corporation
Black Hills Corporation	JEA	Sempra Energy
Boardwalk Pipeline Partners, L.P.	Kinder Morgan Energy Partners, L.P.	Southwest Gas Corporation
Calpine Corporation	Laclede Group, Inc.	Spectra Energy Corp.
CenterpPoint Energy, Inc.	LG&E and KU Energy LLC	TECO Energy, Inc.
Cleco Corporation	Lower Colorado River Authority	Tennessee Valley Authority
CMS Energy Corporation	MDU Resources Group, Inc.	The AES Corporation
Consolidated Edison, Inc.	National Grid USA	The Babcock & Wilcox Company
Dominion Resources, Inc.	Nebraska Public Power District	The Williams Companies, Inc.
DTE Energy Company	New Jersey Resources Corporation	TransCanada Corporation
Duke Energy Corporation	New York Power Authority	Tri-State Generation & Transmission
Dynegy Inc.	NextEra Energy, Inc.	Association, Inc.
Edison International	NiSource Inc.	UGI Corporation
ElectriCities of North Carolina	NorthWestern Corporation	UIL Holdings
Energen Corporation	NRG Energy, Inc.	UNS Energy Corporation
Energy Future Holdings Corp.	OGE Energy Corp.	Vectren Corporation
Energy Solutions, Inc.	Omaha Public Power District	Westar Energy, Inc.
Energy Transfer Partners, L.P.	Oncor Electric Delivery Company LLC	Wisconsin Energy Corporation
EnLink Midstream	Pacific Gas & Electric Company	Xcel Energy Inc.

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 Gulf Power's and Southern Company's performance for the year or period.

A specified weight was not targeted for base salary or annual or long-term performance-based compensation as a percentage of total target compensation opportunities, nor did amounts realized or realizable from prior compensation serve to increase or decrease 2014 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 2014 for each named executive officer below:

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	Salary ($)	Target Annual Performance-Based Compensation ($)	Target Long-Term Performance-Based Compensation ($)	Total Target Compensation Opportunity ($)
S. W. Connally, Jr.	398,242	238,945	517,692	1,154,879
R. S. Teel	253,504	114,077	152,101	519,682
M. L. Burroughs	200,331	80,133	80,103	360,567
J. R. Fletcher	211,255	84,502	84,480	380,237
P. B. Jacob	267,107	120,198	160,246	547,551
B. C. Terry	272,039	122,418	163,191	557,648

The salary levels shown above were not effective until March 2014. 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 2014. The total target compensation opportunity amount shown for Mr. Jacob represents the full amount had he been employed the entire year by Gulf Power. However, the actual amounts Mr. Jacob received for salary and annual performance-based compensation were prorated based on the amount of time he was employed at Gulf Power in 2014. Additionally, the ultimate number of performance shares earned by Mr. Jacob will be prorated based on the time he was employed during the performance period. See the Summary Compensation Table and Grants of Plan-Based Awards in 2014 for more information on the actual compensation amounts Mr. Jacob received.

Mr. Fletcher was employed at Georgia Power as the Vice President of Governmental and Regulatory Affairs prior to his promotion to Vice President at Gulf Power on March 29, 2014. At that time, his base salary and target annual performance-based compensation were increased to $231,324 and $101,343, respectively.

For purposes of comparing the value of the compensation program to the market data, stock options are valued at $2.20 per option and performance shares at $37.54 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 was 40% and 60%, respectively, of the long-term value shown above.

In 2013, Pay Governance analyzed the level of actual payouts for 2012 performance under the annual Performance Pay Program made 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 2014. That analysis was updated in 2014 by Pay Governance for 2013 performance, and those findings were used in establishing goals for 2015.

DESCRIPTION OF KEY COMPENSATION COMPONENTS

2014 Base Salary

Most employees, including all of the named executive officers, received base salary increases in 2014.

With the exception of Southern Company executive officers, including Mr. Connally, base salaries for all Southern Company system officers are within a position level with a base salary range that is established by Southern Company Human Resources staff using the market data described above. Each officer is within one of these established position levels based on the scope of responsibilities that most closely resemble the positions included in the market data described above. The base salary level for individual officers is set within the applicable pre-established range. Factors that influence the specific base salary level within the range include the need to retain an experienced team, internal equity, time in position, and individual performance. Individual performance includes the degree of competence and initiative exhibited and the individual's relative contribution to the achievement of financial and operational goals in prior years.

Base salaries are reviewed annually in February and changes are made effective March 1. The base salary levels established early in the year for the named executive officers were set within the applicable position level salary range and were recommended by the individual named executive officer's supervisor and approved by Southern Company's Chief Executive Officer. Mr. Connally's base salary increase was approved by the Compensation Committee.

2014 Performance-Based Compensation

This section describes performance-based compensation for 2014.

Achieving Operational and Financial Performance Goals — The Guiding Principle for Performance-Based Compensation

The Southern Company system's number one priority is to continue to provide customers outstanding reliability and superior service at reasonable prices while achieving a level of financial performance that benefits Southern Company's stockholders in the short and long term. Operational excellence and business unit and Southern Company financial performance are integral to the achievement of business results that benefit customers and stockholders.

Therefore, in 2014, Gulf Power 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;
- Southern Company dividend growth;
- Long-term, risk-adjusted Southern Company total shareholder return;
- Achieving net income goals to support the Southern Company financial plan and dividend growth; 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.

The Southern Company Chief Executive Officer, with the assistance of Southern Company's Human Resources staff, recommended to the Compensation Committee the program design and award amounts for senior management, including the named executive officers.

2014 Annual Performance-Based Pay Program

Annual Performance Pay Program Highlights
Rewards achievement of annual performance goals:
Business unit net income
Business unit operational performance
Southern Company EPS
Goals are weighted one-third each
Performance results range from 0% to 200% of target, based on level of goal achievement

Overview of Program Design

Almost all employees of Gulf Power, including the named executive officers, are participants.

The performance goals are set at the beginning of each year by the Compensation Committee and include financial and operational goals. In setting goals for pay purposes, the Compensation Committee relies on information on financial and operational goals from the Finance Committee and the Nuclear/Operations Committee of the Southern Company Board of Directors, respectively.

• Business Unit Financial Goal: Net Income
For Southern Company's traditional operating companies, including Gulf Power, and Southern Power, the business unit financial performance goal is net income.

• Business Unit Operational Goals: Varies by business unit
For Southern Company's traditional operating companies, including Gulf Power, operational goals are safety, customer satisfaction, plant availability, transmission and distribution system reliability, major projects (Georgia Power and Mississippi Power), and culture. Each of these operational goals is explained in more detail under Goal Details below. The level of

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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.

• Southern Company Financial Goal: EPS

EPS is defined as Southern 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.

The Compensation Committee may make adjustments, both positive and negative, to goal achievement for purposes of determining payouts. For the financial goals, such adjustments typically include the impact of items considered non-recurring or outside of normal operations or not anticipated in the business plan when the financial goals were established and of sufficient magnitude to warrant recognition. As reported in Gulf Power's Annual Report on Form 10-K for the year ended December 31, 2013, the Compensation Committee did not follow its usual practice, and the charges taken in 2013 related to Mississippi Power's construction of the Kemper IGCC were not excluded from goal achievement results. Because the charges were not excluded, the payout levels for all employees, including the named executive officers, were reduced significantly in 2013. In 2014, Southern Company recorded pre-tax charges to earnings of $868 million ($536 million after-tax, or $0.59 per share) (2014 Kemper IGCC Charges) due to estimated probable losses relating to the Kemper IGCC. Additionally, Southern Company adjusted its 2014 net income by $17 million after-tax (or $0.02 per share) relating to the reversal of previously recognized revenues recorded in 2014 and 2013 and the recognition of carrying costs associated with the 2015 Mississippi Supreme Court decision that reversed the Mississippi PSC's March 2013 rate order associated with the Kemper IGCC (together with the 2014 Kemper IGCC Charges, 2014 Kemper IGCC Charges and Adjustments). The Compensation Committee reviewed the impact of the 2014 Kemper IGCC Charges and Adjustments on goal achievement and payout levels for all Southern Company system employees, including the named executive officers. The Compensation Committee determined that, given the action taken last year and the high levels of achievement of other performance goals in 2014, it was not appropriate to reduce payouts earned in 2014 under the broad-based program applicable to all participating employees. Therefore, the Compensation Committee made an adjustment to exclude the impact of the 2014 Kemper IGCC Charges and Adjustments ($0.61 per share) from earnings as it relates to the EPS goal payout for most Southern Company system employees.

As described in greater detail below in Calculating Payouts, Mr. Burroughs is paid in part based on the equity-weighted average of the business unit net income results, which includes the net income goal achievement for Mississippi Power. Due to the 2014 Kemper IGCC Charges and Adjustments described above, Mississippi Power recorded a net loss of $328.7 million, resulting in below-threshold performance and would have resulted in no payout associated with the Mississippi Power portion of the net income goal for thousands of employees across the Southern Company system, including Mr. Burroughs, as well as no payout at all for the business unit financial goal for all Mississippi Power employees. With the adjustment made by the Compensation Committee, Mississippi Power's net income for purposes of calculating goal achievement was $224 million. The adjusted net income resulted in a higher payout for the net income goal for all Mississippi Power employees as well as a higher payout associated with the overall equity-weighted average net income results for several thousand other employees across the Southern Company system whose payouts are determined by the equity-weighted average of the business unit net income results, including Mr. Burroughs.

Under the terms of the program, no payout can be made if events occur that impact Southern Company's financial ability to fund the Common Stock dividend. The 2014 Kemper IGCC Charges and Adjustments described above did not have that effect.

Goal Details

Operational Goals	Description	Why It Is Important
Customer Satisfaction	Customer satisfaction surveys evaluate performance. The survey results provide an overall ranking for each traditional operating company, including Gulf Power, as well as a ranking for each customer segment: residential, commercial, and industrial.	Customer satisfaction is key to operations. Performance of all operational goals 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 Gulf Power's operations.
Availability	Peak season equivalent forced outage rate is an indicator of availability and efficient generation fleet operations during the months when generation needs are greatest. Availability is measured as a percentage of the hours of forced outages out of the total generation hours.	Availability of sufficient power during peak season fulfills the obligation to serve and provide customers with the least cost generating resources.
Nuclear Plant Operations	Nuclear plant performance is evaluated by measuring nuclear safety as rated by independent industry evaluators, as well as by a quantitative score comprised of various plant performance indicators. Plant reliability and operational availability 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	The Southern Company system is committed to the safe, compliant, and high-quality 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, as well as excellence in transition to operations and prudent decision-making related to these two major projects. An executive review committee is in place for each project to assess progress. A combination of subjective and objective measures is considered in assessing the degree of achievement. Final assessments for each project are approved by either Southern Company’s Chief Executive Officer or Southern Company’s Chief Operating Officer and confirmed by the Nuclear/Operations Committee of Southern Company.	Strategic projects enable the Southern Company system to expand capacity to provide clean, affordable energy to customers across the region.
Safety	Southern 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 Gulf Power's inclusive workplace. This goal includes measures for work environment (employee satisfaction survey), representation of minorities and females in	Supports workforce development efforts and helps to assure diversity of

leadership roles (subjectively assessed), and supplier diversity.	suppliers.

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Financial Performance Goals	Description	Why It Is Important
EPS	Southern Company's net income from ongoing business activities divided by average shares outstanding during the year.	Supports commitment to provide Southern Company's stockholders solid, risk-adjusted returns.
Net Income	For the traditional operating companies, including Gulf Power, and Southern Power, the business unit financial performance goal is net income after dividends on preferred and preference stock.	Supports delivery of Southern Company stockholder value and contributes to Gulf Power's and Southern Company's sound financial policies and stable credit ratings.

The range of business unit and Southern Power net income goals and Southern Company EPS goals for 2014 is shown below. Overall Southern Company performance is determined by the equity-weighted average of the business unit net income goal payouts.

Level of Performance	Alabama Power ($, in millions)	Georgia Power ($, in millions)	Gulf Power ($, in millions)	Mississippi Power ($, in millions)*	Southern Power ($, in millions)	EPS ($)*
Maximum	774	1,258	153.0	240.7	175	2.90
Target	717	1,160	140.2	218.6	135	2.76
Threshold	661	1,063	127.4	196.4	95	2.62

*Excluding impact of the 2014 Kemper IGCC Charges and Adjustments.

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.

2014 Achievement

Actual 2014 goal achievement is shown in the following tables.

Operational Goal Results:

Gulf Power (Ms. Terry and Messrs. Connally, Teel, Burroughs, Fletcher, and Jacob)

Goal	Achievement Percentage
Customer Satisfaction	200
Reliability	184
Availability	200
Safety	30
Culture	127
Total Gulf Power Operational Goal Performance Factor	149

Southern Company Generation (Mr. Burroughs)

Goal	Achievement Percentage
Customer Satisfaction	200
Reliability	195
Availability	190
Safety	150
Culture	141
Major Projects - Plant Vogtle Units 3 and 4 Assessment	175
Major Projects - Kemper IGCC Assessment	75
Total Southern Company Generation Operational Goal Performance Factor	168

Georgia Power (Mr. Fletcher)

Goal	Achievement Percentage
Customer Satisfaction	200
Reliability	172
Availability	200
Safety	80
Culture	137
Major Projects - Plant Vogtle Units 3 and 4 Assessment	175
Total Georgia Power Operational Goal Performance Factor	162

Financial Performance Goal Results:

Goal	Result	Achievement Percentage (%)
Gulf Power Net Income	$140.18	100
Georgia Power Net Income	$1,225.01	166
Southern Power Net Income	$172.30	193
Corporate Net Income Result	Equity-Weighted Average(1)	163
EPS (from ongoing business activities)	$2.80(2)	176

(1) The Corporate Net Income Result is the equity-weighted average of the business unit net income results, including the net income result for Mississippi Power. Mississippi Power’s net income result for this purpose was impacted by the adjustment for the 2014 Kemper IGCC Charges and Adjustments ($553 million on an after tax basis). Mississippi Power recorded a net loss, as determined in accordance with generally accepted accounting principles in the United States (GAAP), of $328.7 million. Payouts under the Performance Pay Program were determined using a net income performance result that differed from Mississippi Power's net income as determined in accordance with GAAP.

(2) The EPS result shown in the table excludes the 2014 Kemper IGCC Charges and Adjustments ($0.61 per share) as described above. EPS, as determined in accordance with GAAP, was $2.19 per share. Payouts under the Performance Pay Program were determined using an EPS performance result that different from EPS as determined in accordance with GAAP.

Calculating Payouts:

All of the named executive officers are paid based on Southern Company EPS performance. With the exception of Messrs. Burroughs and Fletcher, all of the named executive officers are paid based on Gulf Power net income and operational performance. Southern Company Generation officers, including Mr. Burroughs, are paid based on the goal achievement of the traditional operating company supported (60%) and Southern Company Generation (40%). The Southern Company Generation business unit financial goal is based on the equity-weighted average net income payout results of the traditional operating companies and Southern Power. With the exception of the culture and safety goals, Southern Company Generation's operational goal results are the corporate/aggregate operational goal results. Mr. Fletcher's payout is prorated based on the time he was employed at Georgia Power and at Gulf Power. Mr. Jacob's payout is prorated based on the amount of time he was employed at Gulf Power during 2014.

A total performance factor is determined by adding the applicable business unit financial and operational goal performance and the EPS 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(1)	Business Unit Financial Goal Result (%) 1/3 weight	Business Unit Operational Goal Result (%) 1/3 weight	Total Performance Factor (%)
S. W. Connally, Jr.	176	100	149	142
R. S. Teel	176	100	149	142
M. L. Burroughs	176	125	156	152
J. R. Fletcher(2)	176	166/100	162/149	168/142
P. B. Jacob	176	100	149	142
B. C. Terry	176	100	149	142

(1) Excluding the impact of the 2014 Kemper IGCC Charges and Adjustments.

(2) Mr. Fletcher was Vice President of Georgia Power until his promotion to Vice President at Gulf Power on March 29, 2014. Under the terms of the program, Mr. Fletcher's Performance Pay Program results were prorated based on the time he served at each company.

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 ($)	Total Performance Factor (%)	Actual Annual Performance Pay Program Payout ($)
S. W. Connally, Jr.	60	238,945	142	339,302
R. S. Teel	45	114,077	142	161,989
M. L. Burroughs	40	80,133	152	121,801
J. R. Fletcher(1)	40/45	101,343	147.7	149,633
P. B. Jacob(2)	45	120,198	142	57,008
B. C. Terry	45	122,418	142	173,833

(1) When Mr. Fletcher was promoted in March 2014, his target annual Performance Pay Program percentage was increased from 40% to 45%. His actual payout shown is prorated based on the amount of time he spent in each position.

(2) Mr. Jacob retired from Gulf Power in May 2014. His Performance Pay Program payout was prorated based on the amount of time he was employed in 2014. The target amount shown is his full target had he been employed for the entire year. The actual amount shown is the prorated amount Mr. Jacob received.

Long-Term Performance-Based Compensation

2014 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 Southern Company total shareholder return relative to industry peers and stock price appreciation
§ Represent 60% of long-term target value
§ Three-year performance period
§ Performance results can range from 0% to 200% of target
§ Paid in Common Stock at end of performance period

Long-term performance-based awards are intended to promote long-term success and increase Southern Company's stockholder value by directly tying a substantial portion of the named executive officers' total compensation to the interests of Southern Company's stockholders. Long-term performance-based awards also benefit customers by providing competitive compensation that allows Gulf Power to attract, retain, and engage employees who provide focus on serving customers and delivering safe and reliable electric service.

Southern Company 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. Southern Company stock options only generate value if the price of the stock appreciates after the grant date, and performance shares reward employees based on Southern Company total shareholder return relative to industry peers, as well as Common Stock price.

The following table shows the grant date fair value of the long-term performance-based awards granted in 2014.

	Value of Options ($)	Value of Performance Shares ($)	Total Long-Term Value ($)
S. W. Connally, Jr.	207,086	310,606	517,692
R. S. Teel	60,841	91,260	152,101
M. L. Burroughs	32,052	48,051	80,103
J. R. Fletcher	33,801	50,679	84,480
P. B. Jacob	64,106	96,140	160,246
B. C. Terry	65,287	97,904	163,191

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 2014 to Mr. Connally, unvested options are forfeited if he retires from Gulf Power or an affiliate of Gulf Power and accepts a position with a peer company within two years of retirement. The grants made to Mr. Jacob vested upon his retirement. The value of each stock option was derived using the Black-Scholes stock option pricing model. The assumptions used in calculating that amount are discussed in Note 8 to the financial statements of Gulf Power in Item 8 herein. For 2014, the Black-Scholes value on the grant date was

$2.20 per stock option.

Performance Shares

2014-2016 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 grants made in 2014, the value per unit was $37.54. See the Summary Compensation Table and the information accompanying it for more information on the grant date fair value. The total target value for performance share units is divided by the value per unit to determine the number of performance share units granted to each participant, including the named executive officers. Each performance share unit represents one share of Common Stock.

At the end of the three-year performance period (January 1, 2014 through December 31, 2016), the number of units will be adjusted up or down (0% to 200%) based on Southern Company's total shareholder return relative to that of its peers in the Southern Company custom peer group. While in previous years Southern Company's total shareholder return was measured relative to two peer groups (a custom peer group and the Philadelphia Utility Index), the Compensation Committee decided to streamline the performance share peer group for the 2014 grant by eliminating the Philadelphia Utility Index and establishing one custom peer group. The companies in the custom peer group are those that are believed to be most similar to Southern Company in both business model and investors, creating a peer group that is even more aligned with Southern Company's strategy. For performance shares granted in previous years using the dual peer group structure, the final result will be measured using both peer groups as approved by the Compensation Committee at the time of the grant. The custom peer group varies 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 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 custom peer group on the grant date are listed in the following table.

Alliant Energy Corporation	Integrys Energy Group
Ameren Corporation	Pepco Holdings, Inc.
American Electric Power Company, Inc.	PG&E Corporation
CMS Energy Corporation	Pinnacle West Capital Corporation
Consolidated Edison, Inc.	PPL Corporation
DTE Energy Company	SCANA Corporation
Duke Energy Corporation	Wisconsin Energy Corporation
Edison International	Xcel Energy
Eversource 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 2014 through 2016 performance period. Payout for performance between points will be interpolated on a straight-line basis.

Performance vs. Peer Group	Payout (% of Each Performance Share Unit Paid)
90th percentile or higher (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.

2012-2014 Payouts

Performance share grants were made in 2012 with a three-year performance period that ended on December 31, 2014. Based on Southern Company's total shareholder return achievement relative to that of the Philadelphia Utility Index (28% payout) and the custom peer group (0% payout), the payout percentage was 14% 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 ($)	Performance Shares Earned (#)	Value of Performance Shares Earned ($)
S. W. Connally, Jr.	1,944	81,629	272	13,358
R. S. Teel	2,049	86,038	287	14,095
M. L. Burroughs	1,081	45,391	151	7,416
J. R. Fletcher	1,136	47,700	159	7,808
P. B. Jacob(1)	2,185	91,748	238	11,688
B. C. Terry	2,199	92,336	308	15,126

(1) The number of performance shares earned by Mr. Jacob is prorated based on the time he was employed at the Southern Company system during the performance period.

Timing of Performance-Based Compensation

As discussed above, the 2014 annual Performance Pay Program goals and the Southern Company 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 2014 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.

Southern Excellence Awards

Mr. Fletcher received a discretionary award in the amount of $25,000 in recognition of his leadership and superior performance on high-level regulatory matters while employed at Georgia Power in 2014, prior to his employment at Gulf Power.

Retirement and Severance Benefits

Certain post-employment compensation is provided to employees, including the named executive officers, consistent with Gulf Power's goal of providing market-based compensation and benefits.

Retirement Benefits

Generally, all full-time employees of Gulf Power participate in the funded Pension Plan after completing one year of service. Normal retirement benefits become payable when participants attain age 65 and complete five years of participation. Gulf Power also provides unfunded benefits that count salary and annual Performance Pay Program payouts that are ineligible to be counted under the Pension Plan. See the Pension Benefits table and accompanying information for more pension-related benefits information.

Gulf Power also provides supplemental retirement benefits to certain employees that were first employed by Gulf Power, or an affiliate of Gulf Power, in the middle of their careers. Gulf Power has had a supplemental retirement agreement (SRA) with Ms. Terry since 2010. Prior to her employment with the Southern Company system, Ms. Terry provided legal services to Southern Company's subsidiaries. Ms. Terry's agreement provides retirement benefits as if she was employed an additional 10 years. Ms. Terry must remain employed at Gulf Power or an affiliate of Gulf

Power for 10 years from the effective date of the SRA before vesting in the benefits. This agreement provides a benefit which recognizes the expertise she brought to Gulf Power and provides a strong retention incentive to remain with Gulf Power, or one of its affiliates, for the vesting period and beyond.

Gulf Power also provides the Deferred Compensation Plan, which is an unfunded plan that permits participants to defer income as well as certain federal, state, and local taxes until a specified date or their retirement, disability, death, or other separation from service. Up to 50% of base salary and up to 100% of performance-based non-equity compensation may be deferred at the election of eligible employees. All of the named executive officers are eligible to participate in the Deferred Compensation Plan. See the Nonqualified Deferred Compensation table and accompanying information for more information about the Deferred Compensation Plan.

Severance Agreements

In limited circumstances, Gulf Power will provide a severance agreement in exchange for standard legal releases, non-compete agreements, and confidentiality provisions. In connection with Mr. Jacob's retirement in 2014, Gulf Power entered into a severance agreement with Mr. Jacob providing for a severance payment of $667,768, which is included in the Summary Compensation Table.

Change-in-Control Protections

Change-in-control protections, including severance pay and, in some situations, vesting or payment of long-term performance-based awards, are provided upon a change in control of Southern Company or Gulf Power coupled with an involuntary termination not for cause or a voluntary termination for "Good Reason." This means there is a "double trigger" before severance benefits are paid; i.e., there must be both a change in control and a termination of employment. Severance payment amounts are two times salary plus target Performance Pay Program opportunity for Mr. Connally and one times salary plus Performance Pay Program opportunity for the other named executive officers. No excise tax gross-up would be provided. More information about severance arrangements is included under Potential Payments upon Termination or Change in Control. Change-in-control protections allow executive officers to focus on potential transactions that are in the best interest of shareholders.

Perquisites

Gulf Power provides limited ongoing perquisites to its executive officers, including the named executive officers, consistent with Gulf Power's goal of providing market-based compensation and benefits. The perquisites provided in 2014, including amounts, are described in detail in the information accompanying the Summary Compensation Table. No tax assistance is provided on perquisites for the President and Chief Executive Officer, except on certain relocation-related benefits.

PERFORMANCE-BASED COMPENSATION PROGRAM CHANGES FOR 2015

In early 2015, the Compensation Committee made several changes to the performance-based compensation programs, impacting 2015 compensation. These changes affect both the annual Performance Pay Program as well as the long-term performance-based compensation program and are described below.

Annual Performance-Based Pay Program

Beginning in 2015, the annual performance-based pay program will incorporate individual goals for all executive officers of Southern Company, including Mr. Connally. Currently, the goals are equally weighted between the EPS goal, the applicable business unit net income goal, and the applicable business unit operational goals. Starting with the 2015 annual Performance Pay Program goals, the Compensation Committee added an individual goal component (weighted 10%), and changed the weights for the EPS goal and business unit financial and operational goals (weighted 30% each) for Mr. Connally. The other named executive officers were not affected by this change.

Long-Term Performance-Based Compensation

Since 2010, the Southern Company system's long-term performance-based compensation program has included two components: stock options and performance shares. After reviewing current market practices with Pay Governance, the Compensation Committee decided to modify the long-term performance-based compensation program to further align the compensation program with peers in the utility industry and create better alignment of pay with long-term performance. Beginning with long-term performance-based equity grants made in early 2015, the long-term performance-based program consists exclusively of performance shares. The new structure maintains the three-year performance cycle described earlier in this CD&A for performance shares but expands the performance metrics from one (relative total shareholder return) to three metrics. The new program now includes relative total shareholder return (50%), cumulative EPS from ongoing operations over a three-year period (25%), and equity-weighted return on equity (ROE) (25%). Under the new program, dividends will accrue on performance shares throughout the performance period, and eligible new hires and newly promoted employees will receive interim prorated grants of performance shares instead of stock options.

The continued use of relative total shareholder return as a metric in the long-term performance program maintains consistency with the previous program as well as allows Southern Company to measure its performance against a custom group of regulated peers. The new EPS goal measures cumulative EPS from ongoing operations over a three-year period and motivates ongoing earnings growth to support Southern Company's dividends and achievement of strategic financial objectives. The new equity-weighted ROE goal measures traditional operating company performance from ongoing operations over a three-year period and is set to encourage

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top quartile ROE performance. Both the EPS and ROE goals are subject to a gateway goal focused on Southern Company's credit ratings. If Southern Company fails to meet the credit rating requirements established by the Compensation Committee, there will be no payout associated with the EPS and ROE goals.

EXECUTIVE STOCK OWNERSHIP REQUIREMENTS

Officers of Gulf Power that are in a position of Vice President or above are subject to stock ownership requirements. All of the named executive officers are covered by the requirements. Ownership requirements further align the interest of officers and Southern Company's stockholders by promoting a long-term focus and long-term share ownership. The types of ownership arrangements counted toward the requirements are shares owned outright, those held in Southern Company-sponsored plans, and Common Stock accounts in the Deferred Compensation Plan and the Supplemental Benefit Plan. One-third of vested Southern Company stock options may be counted, but, if so, the ownership requirement is doubled. The ownership requirement is reduced by one-half at age 60.

The requirements are expressed as a multiple of base salary as shown below.

	Multiple of Salary without Counting Stock Options	Multiple of Salary Counting 1/3 of Vested Options
S. W. Connally, Jr.	3 Times	6 Times
R. S. Teel	2 Times	4 Times
M. L. Burroughs	1 Times	2 Times
J. R. Fletcher	2 Times	4 Times
B. C. Terry	2 Times	4 Times

Newly-elected officers have approximately five years from the date of their election to meet the applicable ownership requirement. Newly-promoted officers have approximately five years from the date of their promotion to meet the increased ownership requirements. All of the named executive officers are meeting their respective ownership requirement. Mr. Jacob is retired and is therefore no longer subject to stock ownership requirements.

POLICY ON RECOVERY OF AWARDS

Southern Company's Omnibus Incentive Compensation Plan provides that, if Southern Company or Gulf Power is required to prepare an accounting restatement due to material noncompliance as a result of misconduct, and if an executive officer of Gulf Power knowingly or grossly negligently engaged in or failed to prevent the misconduct or is subject to automatic forfeiture under the Sarbanes-Oxley Act of 2002, the executive officer must repay the amount of any payment in settlement of awards earned or accrued during the 12-month period following the first public issuance or filing that was restated.

POLICY REGARDING HEDGING THE ECONOMIC RISK OF STOCK OWNERSHIP

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

COMPENSATION COMMITTEE REPORT

The Compensation Committee met with management to review and discuss the CD&A. Based on such review and discussion, the Compensation Committee recommended to the Southern Company Board of Directors that the CD&A be included in Gulf Power's Annual Report on Form 10-K for the fiscal year ended December 31, 2014. The Southern Company Board of Directors approved that recommendation.

Members of the Compensation Committee:

Henry A. Clark III, Chair
David J. Grain
Veronica M. Hagen
William G. Smith, Jr.
Steven R. Specker

SUMMARY COMPENSATION TABLE

The Summary Compensation Table shows the amount and type of compensation received or earned in 2012, 2013, and 2014 by the named executive officers, except as noted below.

Name and Principal Position (a)	Year (b)	Salary ($) (c)	Bonus ($) (d)	Stock Awards ($) (e)	Option Awards ($) (f)	Non-Equity Incentive Plan Compensation ($) (g)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($) (h)	All Other Compensation ($) (i)	Total ($) (j)
S. W. Connally,	2014	393,907	—	310,606	207,086	339,302	496,800	25,948	1,773,649
Jr.	2013	372,977	—	293,018	195,363	164,557	54,607	25,602	1,106,124
President, Chief Executive Officer, and Director	2012	295,103	24,376	81,629	54,420	249,526	431,809	179,308	1,316,171
R. S. Teel	2014	252,110	—	91,260	60,841	161,989	157,002	17,166	740,368
Vice President	2013	244,903	—	88,614	59,101	80,895	—	17,004	490,517
and Chief Financial Officer	2012	236,882	—	86,038	57,379	143,335	118,474	15,610	657,718
M. L. Burroughs	2014	199,209	—	48,051	32,052	121,801	213,219	9,893	624,225
Vice President	2013	193,498	—	46,656	31,118	59,127	—	11,225	341,624
	2012	187,855	—	45,391	30,269	94,634	204,035	12,218	574,402
J. R. Fletcher Vice President	2014	224,547	25,045	50,679	33,801	149,633	273,148	89,971	846,824
P. B. Jacob	2014	94,293	—	96,140	64,106	57,008	316,172	681,567	1,309,286
Former Vice	2013	258,605	—	93,393	62,272	85,236	—	19,033	518,539
President	2012	253,959	—	91,748	61,169	145,616	310,532	16,671	879,695
B. C. Terry	2014	270,543	—	97,904	65,287	173,833	245,578	17,664	870,809
Vice President	2013	262,809	—	95,094	63,419	86,809	—	16,735	524,866
	2012	255,634	—	92,336	61,573	159,332	210,941	16,910	796,726

Column (a)

Mr. Fletcher was not an executive officer of Gulf Power until 2014.

Column (d)

The amount shown for 2014 for Mr. Fletcher represents a Southern Excellence Award as described in the CD&A and the value of a non-cash safety award he received while employed at Georgia Power. All employees of Georgia Power with a perfect individual safety record in the prior year, including Mr. Fletcher, earned a safety award.

Column (e)

This column does not reflect the value of stock awards that were actually earned or received in 2014. Rather, as required by applicable rules of the SEC, this column reports the aggregate grant date fair value of performance shares granted in 2014. 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, 2016. 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 2014 to Ms. Terry and Messrs. Connally, Teel, Burroughs, and Fletcher, assuming that the highest level of performance is achieved, is $195,808, $621,212, $182,520, $96,102, and $101,358, respectively (200% of the amount shown in the table). Because Mr. Jacob retired from Gulf Power on May 3, 2014, the maximum amount he could earn is $21,398, which is prorated based on the number of months he was employed during the performance period. See Note 8 to the financial statements of Gulf Power in Item 8 herein for a discussion of the assumptions used in calculating these amounts.

Column (f)

This column reports the aggregate grant date fair value of stock options granted in the applicable year. See Note 8 to the financial statements of Gulf Power in Item 8 herein for a discussion of the assumptions used in calculating these amounts.

Column (g)

The amounts in this column are the 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, 2014. 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, 2012, 2013, and 2014. Because Mr. Jacob retired in 2014, the amount reported for him in 2014 reflects the actual benefits expected to be paid after the measurement date. The Pension Benefits as of each measurement date are based on the named executive officer's age, pay, and service accruals and the plan provisions applicable as of the measurement date. The actuarial present values as of each measurement date reflect the assumptions Gulf Power selected for cost purposes as of that measurement date; however, the named executive officers were assumed to remain employed at Gulf Power or any Southern Company subsidiary until their benefits commence at the pension plans' stated normal retirement date, generally age 65. As a result, the amounts in column (h) related to Pension Benefits represent the combined impact of several factors: growth in the named executive officer's Pension Benefits over the measurement year; impact on the total present values of one year shorter discounting period due to the named executive officer being one year closer to normal retirement; impact on the total present values attributable to changes in assumptions from measurement date to measurement date; and impact on the total present values attributable to plan changes between measurement dates. In general, all of the named executive officers saw an increase in their pension values due to a decrease in discount rates and updated mortality rates.

For more information about the Pension Benefits and the assumptions used to calculate the actuarial present value of accumulated benefits as of December 31, 2014, 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, 2013 and December 31, 2014 are:

- Discount rate for the Pension Plan was decreased to 4.20% as of December 31, 2014 from 5.05% as of December 31, 2013,
- Discount rate for the supplemental pension plans was decreased to 3.75% as of December 31, 2014 from 4.50% as of December 31, 2013, and
- Mortality rates for all plans were updated due to the release of new mortality tables.

This column also reports above-market earnings on deferred compensation under the Deferred Compensation Plan (DCP). However, there were no above-market earnings on deferred compensation in the years reported.

Column (i)

This column reports the following items: perquisites; severance payments; tax reimbursements; employer contributions in 2014 to the Southern Company Employee Savings Plan (ESP), which is a tax-qualified defined contribution plan intended to meet requirements of Section 401(k) of the Internal Revenue Code of 1986, as amended (Code); and contributions in 2014 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 2014 are itemized below.

	Perquisites ($)	Severance Payments ($)	Tax Reimbursements ($)	ESP ($)	SBP ($)	Total ($)
S. W. Connally, Jr.	5,858	—	—	11,709	8,381	25,948
R. S. Teel	4,937	—	314	11,915	—	17,166
M. L. Burroughs	1,203	—	102	8,588	—	9,893
J. R. Fletcher	48,432	—	30,087	11,452	—	89,971
P. B. Jacob	6,997	667,768	1,899	4,903	—	681,567
B. C. Terry	5,446	—	515	11,165	538	17,664

Description of Perquisites

Personal Financial Planning is provided for most officers of Gulf Power, including all of the named executive officers. Gulf Power pays for the services of a financial planner on behalf of the officers, up to a maximum amount of $8,700 per year, after the initial year that the benefit is provided. In the initial year, the allowed amount is $15,000. Gulf Power also provides a five-year allowance of $6,000 for estate planning and tax return preparation fees.

Relocation Benefits are provided to cover the costs associated with geographic relocation. In 2014, Mr. Fletcher received relocation-related benefits in the amount of $37,322 in connection with his 2014 relocation from Atlanta, Georgia to Pensacola, Florida. This amount was for the shipment of household goods, incidental expenses related to his move, and home sale and home repurchase assistance. Also, as provided in Gulf Power's relocation policy, tax assistance is provided on the taxable relocation benefits. If Mr. Fletcher terminates within two years of his 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 for the President and Chief Executive Officer. The amount reported for such personal use is the incremental cost of providing the benefit, primarily fuel costs. Also, if seating is available, Southern Company permits a spouse or other family member to accompany an employee on a flight. However, because in such cases the aircraft is being used for a business purpose, there is no incremental cost associated with the family travel, and no amounts are included for such travel. Any additional expenses incurred that are related to family travel are included. In connection with Mr. Fletcher's relocation from Atlanta, Georgia to Pensacola, Florida, Mr. Connally approved personal use of the corporate aircraft for one round-trip flight per month for six months. The perquisite amount shown for Mr. Fletcher includes $8,847 for this approved use of corporate aircraft.

Other Miscellaneous Perquisites. The amount included reflects the full cost to Gulf Power of providing the following items: personal use of company-provided tickets for sporting and other entertainment events and gifts distributed to and activities provided to attendees at company-sponsored events.

GRANTS OF PLAN-BASED AWARDS IN 2014

This table provides information on stock option grants made and goals established for future payouts under the performance-based compensation programs during 2014 by the Compensation Committee.

		Estimated Future Payouts Under Non-Equity Incentive Plan Awards			Estimated Future Payouts Under Equity Incentive Plan Awards			All Other Option Awards: Number of Securities Underlying Options	Exercise or Base Price of Option Awards	Grant Date Fair Value of Stock and Option Awards
Name (a)	Grant Date (b)	Threshold ($) (c)	Target ($) (d)	Maximum ($) (e)	Threshold (#) (f)	Target (#) (g)	Maximum (#) (h)	(#) (i)	($/Sh) (j)	($) (k)
S. W. Connally, Jr.		2,389	238,945	477,890						
	2/10/2014				82	8,274	16,548			310,606
	2/10/2014							94,130	41.28	207,086
R. S. Teel		1,141	114,077	228,154						
	2/10/2014				24	2,431	4,862			91,260
	2/10/2014							27,655	41.28	60,841
M. L. Burroughs		801	80,133	160,265						
	2/10/2014				12	1,280	2,560			48,051
	2/10/2014							14,569	41.28	32,052
J. R. Fletcher		1,013	101,343	202,686						
	2/10/2014				13	1,350	2,700			50,679
	2/10/2014							15,364	41.28	33,801
P. B. Jacob		401	40,146	80,292						
	2/10/2014				25	2,561	5,122			96,140
	2/10/2014							29,139	41.28	64,106
B. C. Terry		1,224	122,418	244,836						
	2/10/2014				26	2,608	5,216			97,904
	2/10/2014							29,676	41.28	65,287

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

These columns reflect the annual Performance Pay Program opportunity granted to the named executive officers in 2014 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. The amounts shown for Mr. Jacob are prorated based on the amount of time he was employed at Gulf Power in 2014. The amounts shown for Mr. Fletcher reflect the increase in salary and annual Performance Pay Program opportunity he received after his promotion to Vice President of Gulf Power on March 29, 2014.

Columns (f), (g), and (h)

These columns reflect the performance shares granted to the named executive officers in 2014 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 2014 through 2016 performance period, based on the extent to which the performance goals are achieved. Any shares not earned are forfeited.

The number of shares shown for Mr. Jacob reflects the full grant he received in February 2014. However, since Mr. Jacob retired in May 2014, the ultimate number of performance shares he will receive will be prorated based on the number of months he was employed by the Southern Company system during the performance period.

Columns (i) and (j)

Column (i) reflects the number of stock options granted to the named executive officers in 2014, as described in the CD&A, and column (j) reflects the exercise price of the stock options, which was the closing price on the grant date.

Column (k)

This column reflects the aggregate grant date fair value of the performance shares and stock options granted in 2014. 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.

The assumptions used in calculating these amounts are discussed in Note 8 to the financial statements of Gulf Power in Item 8 herein.

OUTSTANDING EQUITY AWARDS AT 2014 FISCAL YEAR-END

This table provides information pertaining to all outstanding stock options and stock awards (performance shares) held by or granted to the named executive officers as of December 31, 2014.

	Option Awards				Stock Awards	
Name (a)						
Name (a)	Number of Securities Underlying Unexercised Options Exercisable (#) (b)	Number of Securities Underlying Unexercised Options Unexercisable (#) (c)	Option Exercise Price ($) (d)	Option Expiration Date (e)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#) (f)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($) (g)
S. W. Connally, Jr.	8,521	0	35.78	02/18/2018		
	14,392	0	31.39	02/16/2019		
	16,100	0	37.97	02/14/2021		
	10,702	5,351	44.42	02/13/2022		355,311
	22,302	44,603	44.06	02/11/2023	7,235	406,336
	0	94,130	41.28	02/10/2024	8,274	
R. S. Teel	9,078	0	35.78	02/18/2018		107,453
	9,332	0	31.39	02/16/2019		119,386
	9,629	0	31.17	02/15/2020	2,188	
	16,774	0	37.97	02/14/2021	2,431	

	11,284	5,642	44.42	02/13/2022		
	6,747	13,493	44.06	02/11/2023		
	0	27,655	41.28	02/10/2024		
M. L. Burroughs	289	0	33.81	02/20/2016		
	1,604	0	36.42	02/19/2017		
	2,610	0	35.78	02/18/2018		
	1,207	0	31.17	02/15/2020		
	8,956	0	37.97	02/14/2021	1,152	56,575
	5,953	2,976	44.42	02/13/2022	1,280	62,861
	3,553	7,104	44.06	02/11/2023		
	0	14,569	41.28	02/10/2024		
J. R.Fletcher	3,376	0	37.97	02/14/2021		
	6,247	3,124	44.42	02/13/2022		
	3,728	7,456	44.06	02/11/2023	1,209	59,374
	0	15,364	41.28	02/10/2024	1,350	66,299
P. B. Jacob	0	0			2,306	113,248
					2,561	125,771
B. C. Terry	12,918	0	35.78	02/18/2018		
	18,574	0	37.97	02/14/2021		
	12,109	6,054	44.42	02/13/2022	2,348	115,310
	7,240	14,479	44.06	02/11/2023	2,608	128,079
	0	29,676	41.28	02/10/2024		

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

Stock options vest one-third per year on the anniversary of the grant date. Options granted from 2006 through 2011 with expiration dates from 2016 through 2021 were fully vested as of December 31, 2014. The options granted in 2012, 2013, and 2014 become fully vested as shown below.

Year Option Granted	Expiration Date	Date Fully Vested
2012	February 13, 2022	February 13, 2015
2013	February 11, 2023	February 11, 2016
2014	February 10, 2024	February 10, 2017

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)

In accordance with SEC rules, column (f) reflects the target number of performance shares that can be earned at the end of each three-year performance period (December 31, 2015 and 2016) that were granted in 2013 and 2014, respectively. The performance shares granted for the 2012 through 2014 performance period vested December 31, 2014 and are shown in the Option Exercises and Stock Vested in 2014 table below. The value in column (g) is derived by multiplying the number of shares in column (f) by the Common Stock closing price on December 31, 2014 ($49.11). The ultimate number of shares earned, if any, will be based on the actual performance results at the end of each respective performance period. The ultimate number of shares earned by Mr. Jacob will be prorated based on the number of months he was employed by the Southern Company system during the performance periods. See further discussion of performance shares in the CD&A. See also Potential Payments upon Termination or Change in Control for more information about the treatment of performance shares under different termination and change-in-control events.

OPTION EXERCISES AND STOCK VESTED IN 2014

	Option Awards		Stock Awards	
Name	Number of Shares Acquired on Exercise (#)	Value Realized on Exercise ($)	Number of Shares Acquired on Vesting (#)	Value Realized on Vesting ($)
(a)	(b)	(c)	(d)	(e)
S. W. Connally, Jr.	21,795	274,917	272	13,358
R. S. Teel	15,265	168,574	287	14,095
M. L. Burroughs	—	—	151	7,416
J. R. Fletcher	6,905	58,915	159	7,808
P. B. Jacob	112,474	758,786	238	11,688
B. C. Terry	39,302	494,815	308	15,126

Columns (b) and (c)

Column (b) reflects the number of shares acquired upon the exercise of stock options during 2014 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 2012 through 2014 performance period that vested on December 31, 2014. 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 ($49.11).

PENSION BENEFITS AT 2014 FISCAL YEAR-END

Name	Plan Name	Number of Years Credited Service (#)	Present Value of Accumulated Benefit ($)	Payments During Last Fiscal Year ($)
(a)	(b)	(c)	(d)	(e)
	Pension Plan	23.17	595,352	0
S.W. Connally, Jr.	SBP-P	23.17	454,047	0
	SERP	23.17	351,143	0
	Pension Plan	14.33	349,590	0
R. S. Teel	SBP-P	14.33	42,360	0
	SERP	14.33	95,548	0
	Pension Plan	22.58	637,373	0
M. L. Burroughs	SBP-P	22.58	64,888	0
	SERP	22.58	133,832	0
	Pension Plan	24.58	585,977	0
J. R. Fletcher	SBP-P	24.58	101,222	0
	SERP	24.58	176,582	0
	Pension Plan	30.75	1,419,925	46,851
P. B. Jacob	SBP-P	30.75	269,172	28,796
	SERP	30.75	263,763	28,218
	Pension Plan	12.50	334,389	0
B. C. Terry	SBP-P	12.50	52,591	0
	SERP	12.50	90,190	0
	SRA	10.00	397,417	0

Pension Plan

The Pension Plan is a tax-qualified, funded plan. It is Southern Company's primary retirement plan. Generally, all full-time employees participate in this plan after one year of service. Normal retirement benefits become payable when participants attain age 65 and complete five years of participation. The plan benefit equals the greater of amounts computed using a "1.7% offset formula" and a "1.25% formula," as described below. Benefits are limited to a statutory maximum.

The 1.7% offset formula amount equals 1.7% of final average pay times years of participation less an offset related to Social Security benefits. The offset equals a service ratio times 50% of the anticipated Social Security benefits in excess of $4,200. The service ratio adjusts the offset for the portion of a full career that a participant has worked. The highest three rates of pay out of a participant's last 10 calendar years of service are averaged to derive final average pay. The 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 2014 was $260,000.

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 of pay.

Early retirement benefits become payable once plan participants have, during employment, attained age 50 and completed 10 years of participation. Participants who retire early from active service receive benefits equal to the amounts computed using the same formulas employed at normal retirement. However, a 0.3% reduction applies for each month (3.6% for each year) prior to normal retirement that participants elect to have their benefit payments commence. For example, 64% of the formula benefits are payable starting at age 55. As of December 31, 2014, Ms. Terry and Messrs. Connally, Fletcher, and Teel were not retirement-eligible.

The Pension Plan's benefit formulas produce amounts payable monthly over a participant's post-retirement lifetime. At retirement, plan participants can choose to receive their benefits in one of seven alternative forms of payment. All forms pay benefits monthly over the lifetime of the retiree or the joint lifetimes of the retiree and a spouse. A reduction applies if a retiring participant chooses a payment form other than a single life annuity. The reduction makes the value of the benefits paid in the form chosen comparable to what it would have been if benefits were paid as a single life annuity over the retiree's life.

Participants vest in the Pension Plan after completing five years of service. As of December 31, 2014, all of the named executive officers are vested in their Pension Plan benefits. Participants who terminate employment after vesting can elect to have their pension benefits commence at age 50 if they participated in the Pension Plan for 10 years. If such an election is made, the early retirement reductions that apply are actuarially determined factors and are larger than 0.3% per month.

If a participant dies while actively employed and is either age 50 or vested in the Pension Plan as of date of death, benefits will be paid to a surviving spouse. A survivor's benefit equals 45% of the monthly benefit that the participant had earned before his or her death. Payments to a surviving spouse of a participant who could have retired will begin immediately. Payments to a survivor of a participant who was not retirement-eligible will begin when the deceased participant would have attained age 50.

After commencing, survivor benefits are payable monthly for the remainder of a survivor's life. Participants who are eligible for early retirement may opt to have an 80% survivor benefit paid if they die; however, there is a charge associated with this election.

If participants become totally disabled, periods that Social Security or employer-provided disability income benefits are paid will count as service for benefit calculation purposes. The crediting of this additional service ceases at the point a disabled participant elects to commence retirement payments. Outside of this extra service crediting, the normal 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.

Supplemental Retirement Agreements (SRA)

Gulf Power also provides supplemental retirement benefits to certain employees that were first employed by Gulf Power, or an affiliate of Gulf Power, in the middle of their careers and generally provide for additional retirement benefits by giving credit for years of employment prior to employment with Gulf Power or one of its affiliates. These supplemental retirement benefits are also unfunded and not tax qualified. Information about the SRA with Ms. Terry is included in the CD&A.

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Pension Benefit Assumptions

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

- Discount rate - 4.20% Pension Plan and 3.75% supplemental plans as of December 31, 2014,
- Retirement date - Normal retirement age (65 for all named executive officers),
- Mortality after normal retirement - RP-2014 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 for the Pension Plan, the SBP-P, and the SERP is one year less than the number of years of employment.

Columns (d) and (e)

For Mr. Jacob, who retired May 3, 2014, column (d) reflects the actual benefits expected to be paid, and column (e) reflects the actual amount paid under the Pension Plan, the SBP-P, and the SERP in 2014, as described above.

NONQUALIFIED DEFERRED COMPENSATION AS OF 2014 FISCAL YEAR-END

Name (a)	Executive Contributions in Last FY ($) (b)	Registrant Contributions in Last FY ($) (c)	Aggregate Earnings in Last FY ($) (d)	Aggregate Withdrawals/ Distributions ($) (e)	Aggregate Balance at Last FYE ($) (f)
S. W. Connally, Jr.	—	8,381	6,690	—	127,836
R. S. Teel	—	—	33	—	162
M. L. Burroughs	—	—	—	—	—
J. R. Fletcher	—	—	—	—	—
P. B. Jacob	8,524	—	45,110	49,994	413,995
B. C. Terry	43,405	538	25,998	—	270,397

Southern Company provides the DCP which is designed to permit participants to defer income as well as certain federal, state, and local taxes until a specified date or their retirement or other separation from service. Up to 50% of base salary and up to 100% of performance-based non-equity compensation may be deferred at the election of eligible employees. All of the named executive officers are eligible to participate in the DCP.

Participants have two options for the deemed investments of the amounts deferred - the Stock Equivalent Account and the Prime Equivalent Account. Under the terms of the DCP, participants are permitted to transfer between investments

at any time.
The amounts deferred in the Stock Equivalent Account are treated as if invested at an equivalent rate of return to that of an actual investment in Common Stock, including the crediting of dividend equivalents as such are paid by Southern Company from time to time. It provides participants with an equivalent opportunity for the capital appreciation (or loss) and income of that of a Southern Company stockholder. During 2014, the rate of return in the Stock Equivalent Account was 25.27%.

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

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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 2014 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 2014. 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 2014 were the amounts that were earned as of December 31, 2013 but not payable until the first quarter of 2014. These amounts are not reflected in the Summary Compensation Table because that table reports performance-based compensation that was earned in 2014, but not payable until early 2015. These deferred amounts may be distributed in a lump sum or in up to 10 annual installments at termination of employment or in a lump sum at a specified date, at the election of the participant.

Column (c)

This column reflects contributions under the SBP. Under the Code, employer matching contributions are prohibited under the ESP on employee contributions above stated limits in the ESP, and, if applicable, above legal limits set forth in the Code. The SBP is a nonqualified deferred compensation plan under which contributions are made that are prohibited from being made in the ESP. The contributions are treated as if invested in Common Stock and are payable in cash upon termination of employment in a lump sum or in up to 20 annual installments, at the election of the participant. The amounts reported in this column also were reported in the All Other Compensation column in the Summary Compensation Table.

Column (d)

This column reports earnings or losses on both compensation the named executive officers elected to defer and on employer contributions under the SBP.

Column (f)

This column includes amounts that were deferred under the DCP and contributions under the SBP in prior years and reported in Gulf Power's prior years' Information Statements or Annual Reports on Form 10-K. The following chart shows the amounts reported in Gulf Power's prior years' Information Statements or Annual Reports on Form 10-K.

Name	Amounts Deferred under the DCP Prior to 2014 and Reported in Prior Years' Information Statements or Annual Reports on Form 10-K ($)	Employer Contributions under the SBP Prior to 2014 and Reported in Prior Years' Information Statements or Annual Reports on Form 10-K ($)	Total ($)
S. W. Connally, Jr.	31,742	10,506	42,248
R. S. Teel	—	—	—
M. L. Burroughs	—	—	—
J. R. Fletcher	—	—	—
P. B. Jacob	282,289	23,274	305,563
B. C. Terry	243,752	950	244,702

POTENTIAL PAYMENTS UPON TERMINATION OR CHANGE IN CONTROL

This section describes and estimates payments that could be made to the named executive officers serving as of December 31, 2014 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, 2014 and assumes that the price of Common Stock is the closing market price on December 31, 2014.

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Description of Termination and Change-in-Control Events

The following charts list different types of termination and change-in-control events that can affect the treatment of payments under the compensation and benefit programs. No payments are made under the change-in-control severance program unless, within two years of the change in control, the named executive officer is involuntarily terminated or voluntarily terminates for Good Reason. (See the description of Good Reason below.)

Traditional Termination Events

- Retirement or Retirement-Eligible - Termination of a named executive officer who is at least 50 years old and has at least 10 years of credited service.
- Resignation - Voluntary termination of a named executive officer who is not retirement-eligible.
- Lay Off - Involuntary termination of a named executive officer who is not retirement-eligible not for cause.
- Involuntary Termination - Involuntary termination of a named executive officer for cause. Cause includes individual performance below minimum performance standards and misconduct, such as violation of Gulf Power's Drug and Alcohol Policy.
- Death or Disability - Termination of a named executive officer due to death or disability.

Change-in-Control-Related Events

At the Southern Company or Gulf Power level:

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

At the employee level:

- Involuntary Change-in-Control Termination or Voluntary Change-in-Control Termination for Good Reason - Employment is terminated within two years of a change in control, other than for cause, or the employee voluntarily terminates for Good Reason. Good Reason for voluntary termination within two years of a change in control generally is satisfied when there is a material reduction in salary, performance-based compensation opportunity or benefits, relocation of over 50 miles, or a diminution in duties and responsibilities.

The following chart describes the treatment of different pay and benefit elements in connection with the Traditional Termination Events 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.
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.

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	Southern Company Change-in-Control I	Southern Company Change-in-Control II	Southern Company Termination or Gulf Power Change in Control	Involuntary Change-in-Control-Related Termination or Voluntary Change-in-Control-Related Termination for Good Reason
Nonqualified Pension Benefits (except SRA)	All SERP-related benefits vest if participants vested in tax-qualified pension benefits; otherwise, no impact. SBP - pension-related benefits vest for all participants and single sum value of benefits earned to change-in-control date paid following termination or retirement.	Benefits vest for all participants and single sum value of benefits earned to the change-in-control date paid following termination or retirement.	Same as Southern Company Change-in-Control II.	Based on type of change-in-control event.
SRA	Not affected by change-in-control events.	Not affected by change-in-control events.	Not affected by change-in-control events.	Vest.
Annual Performance Pay Program	If no program termination, paid at greater of target or actual performance. If program terminated within two years of change in control, prorated at target performance level.	Same as Southern Company Change-in-Control I.	Prorated at target performance level.	If not otherwise eligible for payment, if the program is still in effect, prorated at target performance level.
Stock Options	Not affected by change-in-control events.	Not affected by change-in-control events.	Vest and convert to surviving company's securities; if cannot convert, pay spread in cash.	Vest.
Performance Shares	Not affected by change-in-control events.	Not affected by change-in-control events.	Vest and convert to surviving company's securities; if cannot convert, pay spread in cash.	Vest.
DCP	Not affected by change-in-control events.	Not affected by change-in-control events.	Not affected by change-in-control events.	Not affected by change-in-control events.

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Program	Southern Company Change-in-Control I	Southern Company Change-in-Control II	Southern Company Termination or Gulf Power Change in Control	Involuntary Change-in-Control-Related Termination or Voluntary Change-in-Control-Related Termination for Good Reason
SBP	Not affected by change-in-control events.	Not affected by change-in-control events.	Not affected by change-in-control events.	Not affected by change-in-control events.
Severance Benefits	Not applicable.	Not applicable.	Not applicable.	One or two times base salary plus target annual performance-based pay.
Healthcare Benefits	Not applicable.	Not applicable.	Not applicable.	Up to five years participation in group healthcare plan plus payment of two or three years' premium amounts.
Outplacement Services	Not applicable.	Not applicable.	Not applicable.	Six months.

Potential Payments

This section describes and estimates payments that would become payable to the named executive officers upon a termination or change in control as of December 31, 2014.

Pension Benefits

The amounts that would have become payable to the named executive officers if the Traditional Termination Events occurred as of December 31, 2014 under the Pension Plan, the SBP-P, the SERP, and, if applicable, an SRA 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, 2014 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, 2014 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. Terry and Messrs. Connally, Fletcher, and Teel were not retirement-eligible on December 31, 2014. The SRA for Ms. Terry contains an additional service requirement for benefit eligibility which was not met as of December 31, 2014. Therefore she was not eligible to receive retirement benefits under the agreement. However, death benefits would be paid to her surviving spouse.

Name	Retirement ($)		Resignation or Involuntary Termination ($)	Death (payments to a spouse) ($)
S. W. Connally, Jr.	Pension	n/a	2,182	3,583
	SBP-P	n/a	453,210	58,157
	SERP	n/a	—	44,977
R. S. Teel	Pension	n/a	1,301	2,163
	SBP-P	n/a	42,275	5,510
	SERP	n/a	—	12,428
M. L. Burroughs	Pension	3,657	All plans treated as retiring	2,697
	SBP-P	7,426		7,426
	SERP	15,316		15,316
J. R. Fletcher	Pension	n/a	1,883	3,093
	SBP-P	n/a	101,166	11,468
	SERP	n/a	—	20,006
B. C. Terry	Pension	n/a	1,181	1,940
	SBP-P	n/a	52,331	6,861
	SERP	n/a	—	11,767
	SRA	n/a	—	51,850

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, the SERP, and the SRA 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, 2014 following a change-in-control-related event, other than a Southern Company Change-in-Control I (which does not impact how pension benefits are paid), are itemized below. These amounts would be paid instead of the benefits shown in the Traditional Termination Events chart above; they are not paid in addition to those amounts.

Name	SBP-P ($)	SERP ($)	SRA ($)	Total ($)
S. W. Connally, Jr.	443,482	342,972	—	786,454
R. S. Teel	41,367	93,310	—	134,677
M. L. Burroughs	74,260	153,162	—	227,422
J. R. Fletcher	98,994	172,695	—	271,689
B. C. Terry	51,207	87,817	386,959	525,983

The pension benefit amounts in the tables above were calculated as of December 31, 2014 assuming payments would begin as soon as possible under the terms of the plans. Accordingly, appropriate early retirement reductions were applied. Any unpaid annual performance-based compensation was assumed to be paid at 1.30 times the target level. Pension Plan benefits were calculated assuming each named executive officer chose a single life annuity form of payment, because that results in the greatest monthly benefit. The single sum values were based on a 3.79% discount rate.

Annual Performance Pay Program
The amount payable if a change in control had occurred on December 31, 2014 is the greater of target or actual performance. Because actual payouts for 2014 performance were above the target level, the amount that would have been payable was the actual amount paid as reported in the CD&A.

Stock Options and Performance Shares (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, 2014. The value of performance shares is calculated using the closing price of Common Stock on December 31, 2014.

The chart below shows the number of stock options for which vesting would be accelerated under a Southern Company Termination and the amount that would be payable under a Southern Company Termination if there were no conversion to the surviving company's stock options. It also shows the number and value of performance shares that would be paid.

	Number of Equity Awards with Accelerated Vesting (#)		Total Number of Equity Awards Following Accelerated Vesting (#)		Total Payable in Cash without Conversion of Equity Awards ($)
Name	Stock Options	Performance Shares	Stock Options	Performance Shares	
S. W. Connally, Jr.	144,084	15,509	216,101	15,509	2,459,809
R. S. Teel	46,790	4,619	109,634	4,619	1,270,952
M. L. Burroughs	24,649	2,432	48,821	2,432	510,197
J. R. Fletcher	25,944	2,559	39,295	2,559	384,010
B. C. Terry	50,209	4,956	101,050	4,956	1,049,729

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
Mr. Burroughs is retirement-eligible. Healthcare benefits are provided to retirees, and there is no incremental payment associated with the termination or change-in-control events. Because the other named executive officers were not retirement-eligible at the end of 2014, healthcare benefits would not become available until each reaches age 50, except in the case of a change-in-control-related termination, as described in the Change-in-Control-Related Events chart. The estimated cost of providing healthcare insurance premiums for up to a maximum of two years for Ms. Terry and Messrs. Fletcher and Teel is $11,322, $29,563, and $29,563, respectively. The estimated cost of providing healthcare insurance premiums for up to a maximum of three years for Mr. Connally is $46,028.

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 he or she may have against the employing company.

The estimated cost of providing the six months of outplacement services is $6,000 per named executive officer. The severance payment is two times the base salary and target payout under the annual Performance Pay Program for Mr. Connally and one 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, 2014 in connection with a change in control.

Name	Severance Amount ($)
S. W. Connally, Jr.	1,274,374
R. S. Teel	367,581
M. L. Burroughs	280,464
J. R. Fletcher	332,667
B. C. Terry	394,457

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DIRECTOR COMPENSATION

Only non-employee directors of Gulf Power are compensated for service on the board of directors.
During 2014, the pay components for non-employee directors were:

Annual cash retainer:	$22,000 per year
Annual stock retainer:	$19,500 per year in Common Stock
Board meeting fees:	If more than five meetings are held in a calendar year, $1,200 will be paid for participation beginning with the sixth meeting.
Committee meeting fees:	If more than five meetings of any one committee are held in a calendar year, $1,000 will be paid for participation in each meeting of that committee beginning with the sixth meeting.

DIRECTOR DEFERRED COMPENSATION PLAN

Any deferred quarterly equity grants or stock retainers are required to be deferred in the Deferred Compensation Plan For Directors of Gulf Power Company (Director Deferred Compensation Plan) and are invested in Common Stock units which earn dividends as if invested in Common Stock. Earnings are reinvested in additional stock units. Upon leaving the board, distributions are made in shares of Common Stock or cash.

In addition, directors may elect to defer up to 100% of their remaining compensation in the Director Deferred Compensation Plan until membership on the board ends. Deferred compensation may be invested as follows, at the director's election:

- in Common Stock units which earn dividends as if invested in Common Stock and are distributed in shares of Common Stock or cash upon leaving the board;
- at prime interest which is paid in cash upon leaving the board.

All investments and earnings in the Director Deferred Compensation Plan are fully vested and, at the election of the director, may be distributed in a lump sum payment or in up to 10 annual distributions after leaving the board.

DIRECTOR COMPENSATION TABLE

The following table reports all compensation to Gulf Power's non-employee directors during 2014, 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.

Name	Fees Earned or Paid in Cash ($)(1)	Stock Awards ($)(2)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)	All Other Compensation ($)(3)	Total ($)
Allan G. Bense	24,400	19,500	0	138	44,038
Deborah H. Calder	24,400	19,500	0	79	43,979
William C. Cramer, Jr.	24,400	19,500	0	79	43,979
Julian B. MacQueen	24,400	19,500	0	138	44,038
J. Mort O'Sullivan III	24,400	19,500	0	303	44,203
Michael T. Rehwinkel	24,400	19,500	0	138	44,038
Winston E. Scott	23,200	19,500	0	107	42,807

(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 reimbursement for taxes on imputed income associated with gifts and activities provided to attendees at Southern Company system-sponsored events.

COMPENSATION RISK ASSESSMENT

Southern Company reviewed its compensation policies and practices, including those of Gulf Power, 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 non-employee directors of Southern Company who have never served as executive officers of Southern Company or Gulf Power. During 2014, none of Southern Company's or Gulf Power's executive officers served on the board of directors of any entities whose directors or executive officers serve on the Compensation Committee.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Security Ownership (Applicable to Gulf Power only).

Security Ownership of Certain Beneficial Owners. Southern Company is the beneficial owner of 100% of the outstanding common stock of Gulf Power. The number of outstanding shares reported in the table below is as of January 31, 2015.

Title of Class	Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class	
Common Stock	The Southern Company 30 Ivan Allen Jr. Boulevard, N.W. Atlanta, Georgia 30308		100	%
	Registrant: Gulf Power	5,642,717		

Security Ownership of Management. The following tables show the number of shares of Common Stock owned by the directors, nominees, and executive officers as of December 31, 2014. It is based on information furnished by the directors, nominees, and executive officers. The shares beneficially 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 on December 31, 2014.

		Shares Beneficially Owned Include:	
Name of Directors, Nominees, and Executive Officers	Shares Beneficially Owned (1)	Deferred Stock Units (2)	Shares Individuals Have Rights to Acquire Within 60 Days (3)
S. W. Connally, Jr.	140,553	0	131,046
Allan G. Bense	3,350	0	0
Deborah H. Calder	2,503	1,999	0
William C. Cramer, Jr.	17,460	17,460	0
Julian B. MacQueen	963	—	0
J. Mort O'Sullivan III	3,721	3,721	0
Michael T. Rehwinkel	480	0	0
Winston E. Scott	7,592	0	0
Michael L. Burroughs	40,327	0	35,557
Jim R. Fletcher	32,455	0	29,391
Richard S. Teel	85,092	0	84,451
Bentina C. Terry	81,808	0	73,991
Directors, Nominees, and Executive Officers as a group (13 people)	431,770	23,180	366,319

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

(2) Indicates the number of deferred stock units held under the Director Deferred Compensation Plan.

(3) Indicates shares of Common Stock that certain executive officers have the right to acquire within 60 days. Shares indicated are included in the Shares Beneficially Owned column.

Changes in Control. Southern Company and Gulf Power know of no arrangements which may at a subsequent date result in any change in control.

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ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE.

Transactions with Related Persons. None.

Review, Approval or Ratification of Transactions with Related Persons.

Gulf Power does not have a written policy pertaining solely to the approval or ratification of "related party transactions." Southern Company has a Code of Ethics as well as a Contract Guidance Manual and other formal written procurement policies and procedures that guide the purchase of goods and services, including requiring competitive bids for most transactions above $10,000 or approval based on documented business needs for sole sourcing arrangements. The approval and ratification of any related party transactions would be subject to these written policies and procedures which include a determination of the need for the goods and services; preparation and evaluation of requests for proposals by supply chain management; the writing of contracts; controls and guidance regarding the evaluation of the proposals; and negotiation of contract terms and conditions. As appropriate, these contracts are also reviewed by individuals in the legal, accounting, and/or risk management/services departments prior to being approved by the responsible individual. The responsible individual will vary depending on the department requiring the goods and services, the dollar amount of the contract, and the appropriate individual within that department who has the authority to approve a contract of the applicable dollar amount.

Director Independence.

The board of directors of Gulf Power consists of seven non-employee directors (Ms. Deborah H. Calder and Messrs. Allan G. Bense, William C. Cramer, Jr., Julian B. MacQueen, J. Mort O'Sullivan, III, Michael T. Rehwinkel, and Winston E. Scott) and Mr. Connally.

Southern Company owns all of Gulf Power's outstanding common stock. Gulf Power has listed only debt securities on the NYSE. Accordingly, under the rules of the NYSE, Gulf Power is exempt from most of the NYSE's listing standards relating to corporate governance. Gulf Power has voluntarily complied with certain NYSE listing standards relating to corporate governance where such compliance was deemed to be in the best interests of Gulf Power's shareholders.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The following represents the fees billed to Gulf Power and Southern Power for the last two fiscal years by Deloitte & Touche LLP, each company's principal public accountant for 2014 and 2013:

	2014	2013
	(in thousands)	
Gulf Power		
Audit Fees (1)	$1,427	$1,395
Audit-Related Fees	—	—
Tax Fees	—	—
All Other Fees	12	—
Total	$1,439	$1,395
Southern Power		
Audit Fees (1)	$1,143	$1,159
Audit-Related Fees	—	—
Tax Fees	—	—
All Other Fees	2	—
Total	$1,145	$1,159

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

The Southern Company Audit Committee (on behalf of Southern Company and its subsidiaries) adopted a Policy of Engagement of the Independent Auditor for Audit and Non-Audit Services that includes requirements for such Audit Committee to pre-approve audit and non-audit services provided by Deloitte & Touche LLP. All of the audit services provided by Deloitte & Touche LLP in fiscal years 2014 and 2013 (described in the footnotes to the table above) and related fees were approved in advance by the Southern Company Audit Committee.

PART IV
Item 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES
(a) The following documents are filed as a part of this report on Form 10-K:
(1) Financial Statements and Financial Statement Schedules:
Management's Report on Internal Control Over Financial Reporting for Southern Company and Subsidiary Companies is listed under Item 8 herein.
Management's Report on Internal Control Over Financial Reporting for Alabama Power is listed under Item 8 herein.
Management's Report on Internal Control Over Financial Reporting for Georgia Power is listed under Item 8 herein.
Management's Report on Internal Control Over Financial Reporting for Gulf Power is listed under Item 8 herein.
Management's Report on Internal Control Over Financial Reporting for Mississippi Power is listed under Item 8 herein.
Management's Report on Internal Control Over Financial Reporting for Southern Power and Subsidiary Companies is listed under Item 8 herein.
Reports of Independent Registered Public Accounting Firm on the financial statements and financial statement schedules for Southern Company and Subsidiary Companies, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power, as well as the Report of Independent Registered Public Accounting Firm on the financial statements of Southern Power and Subsidiary Companies are listed under Item 8 herein.
The financial statements filed as a part of this report for Southern Company and Subsidiary Companies, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power and Subsidiary Companies are listed under Item 8 herein.
The financial statement schedules for Southern Company and Subsidiary Companies, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power are listed in the Index to the Financial Statement Schedules at page S-1.
(2) Exhibits:
Exhibits for Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power are listed in the Exhibit Index at page E-1.

THE SOUTHERN COMPANY
SIGNATURES
Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.
THE SOUTHERN COMPANY

By:	Thomas A. Fanning Chairman, President, and Chief Executive Officer
By:	/s/Melissa K. Caen (Melissa K. Caen, Attorney-in-fact)
Date:	March 2, 2015

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Thomas A. Fanning
Chairman, President,
Chief Executive Officer, and Director
(Principal Executive Officer)

Art P. Beattie
Executive Vice President and Chief Financial
Officer
(Principal Financial Officer)

Ann P. Daiss
Comptroller and Chief Accounting Officer
(Principal Accounting Officer)
Directors:

Juanita Powell Baranco	Donald M. James
Jon A. Boscia	John D. Johns
Henry A. Clark III	Dale E. Klein
David J. Grain	William G. Smith, Jr.
Veronica M. Hagen	Steven R. Specker
Warren A. Hood, Jr.	Larry D. Thompson
Linda P. Hudson	E. Jenner Wood III

By: /s/Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)
Date: March 2, 2015

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ALABAMA POWER COMPANY
SIGNATURES
Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.
ALABAMA POWER COMPANY

By: Mark A. Crosswhite
Chairman, President, and Chief Executive Officer

By: /s/Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)

Date: March 2, 2015
Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Mark A. Crosswhite
Chairman, President, Chief Executive Officer, and Director
(Principal Executive Officer)

Philip C. Raymond
Executive Vice President, Chief Financial Officer, and Treasurer
(Principal Financial Officer)

Anita Allcorn-Walker
Vice President and Comptroller
(Principal Accounting Officer)
Directors:

Whit Armstrong	Malcolm Portera
Ralph D. Cook	Robert D. Powers
David J. Cooper, Sr.	Catherine J. Randall
Anthony A. Joseph	C. Dowd Ritter
Patricia M. King	James H. Sanford
James K. Lowder	John Cox Webb, IV

By: /s/Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)
Date: March 2, 2015

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Table of Contents Index to Financial Statements

GEORGIA POWER COMPANY
SIGNATURES
Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.
GEORGIA POWER COMPANY

By: W. Paul Bowers
Chairman, President, and Chief Executive Officer

By: /s/Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)

Date: March 2, 2015
Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

W. Paul Bowers
Chairman, President, Chief Executive Officer, and Director
(Principal Executive Officer)

W. Ron Hinson
Executive Vice President, Chief Financial Officer, and Treasurer
(Principal Financial Officer)

David P. Poroch
Comptroller and Vice President
(Principal Accounting Officer)
Directors:
Robert L. Brown, Jr.

Anna R. Cablik	Beverly Daniel Tatum
Stephen S. Green	D. Gary Thompson
Jimmy C. Tallent	Clyde C. Tuggle
Charles K. Tarbutton	Richard W. Ussery

By: /s/Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)
Date: March 2, 2015

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GULF POWER COMPANY
SIGNATURES
Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.
GULF POWER COMPANY

By:	S. W. Connally, Jr. President and Chief Executive Officer
By:	/s/Melissa K. Caen (Melissa K. Caen, Attorney-in-fact)
Date:	March 2, 2015

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.
S. W. Connally, Jr.
President, Chief Executive Officer, and Director
(Principal Executive Officer)

Richard S. Teel
Vice President and Chief Financial Officer
(Principal Financial Officer)

Janet J. Hodnett
Comptroller
(Principal Accounting Officer)
Directors:

Allan G. Bense	J. Mort O'Sullivan, III
Deborah H. Calder	Michael T. Rehwinkel
William C. Cramer, Jr.	Winston E. Scott
Julian B. MacQueen	

By: /s/Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)
Date: March 2, 2015

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MISSISSIPPI POWER COMPANY
SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

MISSISSIPPI POWER COMPANY

By: G. Edison Holland, Jr.
Chairman, President, and Chief Executive Officer

By: /s/Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)

Date: March 2, 2015

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

G. Edison Holland, Jr.
Chairman, President, Chief Executive Officer, and Director
(Principal Executive Officer)

Moses H. Feagin
Vice President, Treasurer, and Chief Financial Officer
(Principal Financial Officer)

Cynthia F. Shaw
Comptroller
(Principal Accounting Officer)

Directors:

Carl J. Chaney	Christine L. Pickering
L. Royce Cumbest	Phillip J. Terrell
Thomas A. Dews	M. L. Waters
Mark E. Keenum	

By: /s/Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)

Date: March 2, 2015

SOUTHERN POWER COMPANY
SIGNATURES
Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.
SOUTHERN POWER COMPANY

By: Oscar C. Harper IV
President and Chief Executive Officer

By: /s/Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)

Date: March 2, 2015
Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Oscar C. Harper IV
President, Chief Executive Officer, and Director
(Principal Executive Officer)

William C. Grantham
Vice President, Chief Financial Officer, and Treasurer
(Principal Financial Officer)

Elliott L. Spencer
Comptroller and Corporate Secretary
(Principal Accounting Officer)
Directors:
Art P. Beattie
Thomas A. Fanning
Kimberly S. Greene
James Y. Kerr II
Mark S. Lantrip
Christopher C. Womack

By: /s/Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)
Date: March 2, 2015

Supplemental Information to be Furnished With Reports Filed Pursuant to Section 15(d) of the Act by Registrants Which Have Not Registered Securities Pursuant to Section 12 of the Act:

No annual report, proxy statement, form of proxy or other proxy soliciting material has been sent to security holders of the registrant during the period covered by this Annual Report on Form 10-K for the fiscal year ended December 31, 2014.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Southern Company

We have audited the consolidated financial statements of Southern Company and Subsidiaries (the Company) as of December 31, 2014 and 2013, and for each of the three years in the period ended December 31, 2014, and the Company's internal control over financial reporting as of December 31, 2014, and have issued our report thereon dated March 2, 2015; such report is included elsewhere in this Form 10-K. Our audits also included the consolidated financial statement schedule of the Company (page S-2) listed in Item 15. This consolidated financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/Deloitte & Touche LLP
Atlanta, Georgia
March 2, 2015

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM
To the Board of Directors of
Alabama Power Company
We have audited the financial statements of Alabama Power Company (the Company) (a wholly owned subsidiary of The Southern Company) as of December 31, 2014 and 2013, and for each of the three years in the period ended December 31, 2014, and have issued our report thereon dated March 2, 2015; such report is included elsewhere in this Form 10-K. Our audits also included the financial statement schedule of the Company (Page S-3) listed in Item 15. This financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.
/s/Deloitte & Touche LLP
Birmingham, Alabama
March 2, 2015

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Georgia Power Company

We have audited the financial statements of Georgia Power Company (the Company) (a wholly owned subsidiary of The Southern Company) as of December 31, 2014 and 2013, and for each of the three years in the period ended December 31, 2014, and have issued our report thereon dated March 2, 2015; such report is included elsewhere in this Form 10-K. Our audits also included the financial statement schedule of the Company (Page S-4) listed in Item 15. This financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/Deloitte & Touche LLP
Atlanta, Georgia
March 2, 2015

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Gulf Power Company

We have audited the financial statements of Gulf Power Company (the Company) (a wholly owned subsidiary of The Southern Company) as of December 31, 2014 and 2013, and for each of the three years in the period ended December 31, 2014, and have issued our report thereon dated March 2, 2015; such report is included elsewhere in this Form 10-K. Our audits also included the financial statement schedule of the Company (Page S-5) listed in Item 15. This financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/Deloitte & Touche LLP
Atlanta, Georgia
March 2, 2015

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Mississippi Power Company

We have audited the financial statements of Mississippi Power Company (the Company) (a wholly owned subsidiary of The Southern Company) as of December 31, 2014 and 2013, and for each of the three years in the period ended December 31, 2014, and have issued our report thereon dated March 2, 2015; such report is included elsewhere in this Form 10-K. Our audits also included the financial statement schedule of the Company (Page S-6) listed in Item 15. This financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/Deloitte & Touche LLP
Atlanta, Georgia
March 2, 2015

INDEX TO FINANCIAL STATEMENT SCHEDULES

Schedules I through V not listed above are omitted as not applicable or not required. A Schedule II for Southern Power Company and Subsidiary Companies is not being provided because there were no reportable items for the three-year period ended December 31, 2014. Columns omitted from schedules filed have been omitted because the information is not applicable or not required.

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THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2014, 2013, AND 2012
(Stated in Thousands of Dollars)

		Additions			
Description	Balance at Beginning of Period	Charged to Income	Charged to Other Accounts	Deductions (Note)	Balance at End of Period
Provision for uncollectible accounts					
2014	$17,855	$43,537	$—	$43,139	$18,253
2013	16,984	36,788	—	35,917	17,855
2012	26,155	35,305	—	44,476	16,984

(Note) Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.

ALABAMA POWER COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2014, 2013, AND 2012
(Stated in Thousands of Dollars)

		Additions			
Description	Balance at Beginning of Period	Charged to Income	Charged to Other Accounts	Deductions (Note)	Balance at End of Period
Provision for uncollectible accounts					
2014	$8,350	$14,309	$—	$13,516	$9,143
2013	8,450	12,327	—	12,427	8,350
2012	9,856	10,537	—	11,943	8,450

(Note) Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.

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GEORGIA POWER COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2014, 2013, AND 2012
(Stated in Thousands of Dollars)

		Additions			
Description	Balance at Beginning of Period	Charged to Income	Charged to Other Accounts	Deductions (Note)	Balance at End of Period
Provision for uncollectible accounts					
2014	$5,074	$24,141	$—	$23,139	$6,076
2013	6,259	18,362	—	19,547	5,074
2012	13,038	20,995	—	27,774	6,259

(Note) Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.

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GULF POWER COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2014, 2013, AND 2012
(Stated in Thousands of Dollars)

		Additions			
Description	Balance at Beginning of Period	Charged to Income	Charged to Other Accounts	Deductions (Note)	Balance at End of Period
Provision for uncollectible accounts					
2014	$1,131	$4,304	$—	$3,348	$2,087
2013	1,490	1,900	—	2,259	1,131
2012	1,962	2,611	—	3,083	1,490

(Note) Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.

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MISSISSIPPI POWER COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2014, 2013, AND 2012
(Stated in Thousands of Dollars)

		Additions			
Description	Balance at Beginning of Period	Charged to Income	Charged to Other Accounts	Deductions (Note)	Balance at End of Period
Provision for uncollectible accounts					
2014	$3,018	$562	$—	$2,755	$825
2013	373	3,757	—	1,112	3,018
2012	547	628	—	802	373

(Note) Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.

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EXHIBIT INDEX
The exhibits below with an asterisk (*) preceding the exhibit number are filed herewith. The remaining exhibits have previously been filed with the SEC and are incorporated herein by reference. The exhibits marked with a pound sign (#) are management contracts or compensatory plans or arrangements required to be identified as such by Item 15 of Form 10-K.

(3) Articles of Incorporation and By-Laws

Southern Company

(a)	1	—	Composite Certificate of Incorporation of Southern Company, reflecting all amendments thereto through May 27, 2010. (Designated in Registration No. 33-3546 as Exhibit 4(a), in Certificate of Notification, File No. 70-7341, as Exhibit A, in Certificate of Notification, File No. 70-8181, as Exhibit A, and in Form 8-K dated May 26, 2010, File No. 1-3526, as Exhibit 3.1.)
(a)	2	—	By-laws of Southern Company as amended effective February 11, 2013, and as presently in effect. (Designated in Form 8-K dated February 11, 2013, File No. 1-3526, as Exhibit 3.1.)

Alabama Power

(b)	1	—	Charter of Alabama Power and amendments thereto through April 25, 2008. (Designated in Registration Nos. 2-59634 as Exhibit 2(b), 2-60209 as Exhibit 2(c), 2-60484 as Exhibit 2(b), 2-70838 as Exhibit 4(a)-2, 2-85987 as Exhibit 4(a)-2, 33-25539 as Exhibit 4(a)-2, 33-43917 as Exhibit 4(a)-2, in Form 8-K dated February 5, 1992, File No. 1-3164, as Exhibit 4(b)-3, in Form 8-K dated July 8, 1992, File No. 1-3164, as Exhibit 4(b)-3, in Form 8-K dated October 27, 1993, File No. 1-3164, as Exhibits 4(a) and 4(b), in Form 8-K dated November 16, 1993, File No. 1-3164, as Exhibit 4(a), in Certificate of Notification, File No. 70-8191, as Exhibit A, in Alabama Power's Form 10-K for the year ended December 31, 1997, File No. 1-3164, as Exhibit 3(b)2, in Form 8-K dated August 10, 1998, File No. 1-3164, as Exhibit 4.4, in Alabama Power's Form 10-K for the year ended December 31, 2000, File No. 1-3164, as Exhibit 3(b)2, in Alabama Power's Form 10-K for the year ended December 31, 2001, File No. 1-3164, as Exhibit 3(b)2, in Form 8-K dated February 5, 2003, File No. 1-3164, as Exhibit 4.4, in Alabama Power's Form 10-Q for the quarter ended March 31, 2003, File No 1-3164, as Exhibit 3(b)1, in Form 8-K dated February 5, 2004, File No. 1-3164, as Exhibit 4.4, in Alabama Power's Form 10-Q for the quarter ended March 31, 2006, File No. 1-3164, as Exhibit 3(b)(1), in Form 8-K dated December 5, 2006, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated September 12, 2007, File No. 1-3164, as Exhibit 4.5, in Form 8-K dated October 17, 2007, File No. 1-3164, as Exhibit 4.5, and in Alabama Power's Form 10-Q for the quarter ended March 31, 2008, File No. 1-3164, as Exhibit 3(b)1.)
(b)	2	—	Amended and Restated By-laws of Alabama Power effective February 10, 2014, and as presently in effect. (Designated in Form 8-K dated February 10, 2014, File No 1-3164, as Exhibit 3.1.)

Georgia Power

(c)	1	—	Charter of Georgia Power and amendments thereto through October 9, 2007. (Designated in Registration Nos. 2-63392 as Exhibit 2(a)-2, 2-78913 as Exhibits 4(a)-(2) and 4(a)-(3), 2-93039 as Exhibit 4(a)-(2), 2-96810 as Exhibit 4(a)-2, 33-141 as Exhibit 4(a)-(2), 33-1359 as Exhibit 4(a)(2), 33-5405 as Exhibit 4(b)(2), 33-14367 as Exhibits 4(b)-(2) and 4(b)-(3), 33-22504 as Exhibits 4(b)-(2), 4(b)-(3) and 4(b)-(4), in Georgia Power's Form 10-K for the year ended December 31, 1991, File No. 1-6468, as Exhibits 4(a)(2) and 4(a)(3), in Registration No. 33-48895 as Exhibits 4(b)-(2) and 4(b)-(3), in Form 8-K dated December 10, 1992, File No. 1-6468 as Exhibit 4(b), in

			Form 8-K dated June 17, 1993, File No. 1-6468, as Exhibit 4(b), in Form 8-K dated October 20, 1993, File No. 1-6468, as Exhibit 4(b), in Georgia Power's Form 10-K for the year ended December 31, 1997, File No. 1-6468, as Exhibit 3(c)2, in Georgia Power's Form 10-K for the year ended December 31, 2000, File No. 1-6468, as Exhibit 3(c)2, in Form 8-K dated June 27, 2006, File No. 1-6468, as Exhibit 3.1, and in Form 8-K dated October 3, 2007, File No. 1-6468, as Exhibit 4.5.)
(c)	2	—	By-laws of Georgia Power as amended effective May 20, 2009, and as presently in effect. (Designated in Form 8-K dated May 20, 2009, File No. 1-6468, as Exhibit 3(c)2.)
Gulf Power			
(d)	1	—	Amended and Restated Articles of Incorporation of Gulf Power and amendments thereto through June 17, 2013. (Designated in Form 8-K dated October 27, 2005, File No. 001-31737, as Exhibit 3.1, in Form 8-K dated November 9, 2005, File No. 001-31737, as Exhibit 4.7, in Form 8-K dated October 16, 2007, File No. 001-31737, as Exhibit 4.5, and in Form 8-K dated June 10, 2013, File No. 001-31737, as Exhibit 4.7.)
(d)	2	—	By-laws of Gulf Power as amended effective November 2, 2005, and as presently in effect. (Designated in Form 8-K dated October 27, 2005, File No. 001-31737, as Exhibit 3.2.)

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Mississippi Power			
(e)	1	—	Articles of Incorporation of Mississippi Power, articles of merger of Mississippi Power Company (a Maine corporation) into Mississippi Power and articles of amendment to the articles of incorporation of Mississippi Power through April 2, 2004. (Designated in Registration No. 2-71540 as Exhibit 4(a)-1, in Form U5S for 1987, File No. 30-222-2, as Exhibit B-10, in Registration No. 33-49320 as Exhibit 4(b)-(1), in Form 8-K dated August 5, 1992, File No. 001-11229, as Exhibits 4(b)-2 and 4(b)-3, in Form 8-K dated August 4, 1993, File No. 001-11229, as Exhibit 4(b)-3, in Form 8-K dated August 18, 1993, File No. 001-11229, as Exhibit 4(b)-3, in Mississippi Power's Form 10-K for the year ended December 31, 1997, File No. 001-11229, as Exhibit 3(e)2, in Mississippi Power's Form 10-K for the year ended December 31, 2000, File No. 001-11229, as Exhibit 3(e)2, and in Form 8-K dated March 3, 2004, File No. 001-11229, as Exhibit 4.6.)
(e)	2	—	By-laws of Mississippi Power as amended effective February 28, 2001, and as presently in effect. (Designated in Mississippi Power's Form 10-K for the year ended December 31, 2001, File No. 001-11229, as Exhibit 3(e)2.)
Southern Power			
(f)	1	—	Certificate of Incorporation of Southern Power Company dated January 8, 2001. (Designated in Registration No. 333-98553 as Exhibit 3.1.)
(f)	2	—	By-laws of Southern Power Company effective January 8, 2001. (Designated in Registration No. 333-98553 as Exhibit 3.2.)

(4) Instruments Describing Rights of Security Holders, Including Indentures

With respect to each of Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power Company, such registrant has not included any instrument with respect to long-term debt that does not exceed 10% of the total assets of such registrant and its subsidiaries. Each such registrant agrees, upon request of the SEC, to furnish copies of any or all such instruments to the SEC.

Southern Company			
(a)	1	—	Senior Note Indenture dated as of January 1, 2007, between Southern Company and Wells Fargo Bank, National Association, as Trustee, and indentures supplemental thereto through August 22, 2014. (Designated in Form 8-K dated January 11, 2007, File No. 1-3526, as Exhibits 4.1 and 4.2, in Form 8-K dated March 20, 2007, File No. 1-3526, as Exhibit 4.2, in Form 8-K dated August 13, 2008, File No. 1-3526, as Exhibit 4.2, in Form 8-K dated May 11, 2009, File No. 1-3526, as Exhibit 4.2, in Form 8-K dated October 19, 2009, File No. 1-3526, as Exhibit 4.2, in Form 8-K dated September 13, 2010, File No. 1-3526, as Exhibit 4.2, in Form 8-K dated August 16, 2011, File No. 1-3526, as Exhibit 4.2, in Form 8-K dated August 21, 2013, File No. 1-3526, as Exhibit 4.2, and in Form 8-K dated August 19, 2014, File No. 1-3526, as Exhibits 4.2(a) and 4.2(b).)
Alabama Power			
(b)	1	—	Subordinated Note Indenture dated as of January 1, 1997, between Alabama Power and The Bank of New York Mellon (as successor to JPMorgan Chase Bank, N.A. (formerly known as The Chase Manhattan Bank)), as Trustee, and indentures supplemental thereto through October 2, 2002. (Designated in Form 8-K dated January 9, 1997, File No. 1-3164, as Exhibits 4.1 and 4.2, in Form 8-K dated February 18, 1999, File No. 1-3164, as Exhibit 4.2, and in Form 8-K dated September 26, 2002, File No. 3164, as Exhibits 4.9-A and 4.9-B.)

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(b)	2	—	Senior Note Indenture dated as of December 1, 1997, between Alabama Power and The Bank of New York Mellon (as successor to JPMorgan Chase Bank, N.A. (formerly known as The Chase Manhattan Bank)), as Trustee, and indentures supplemental thereto through August 26, 2014. (Designated in Form 8-K dated December 4, 1997, File No. 1-3164, as Exhibits 4.1 and 4.2, in Form 8-K dated February 20, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated April 17, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated August 11, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated September 8, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated September 16, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated October 7, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated October 28, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated November 12, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated May 19, 1999, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated August 13, 1999, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated September 21, 1999, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated May 11, 2000, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated August 22, 2001, File No. 1-3164, as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated June 21, 2002, File No. 1-3164, as Exhibit 4.2(a), in Form 8-K dated October 16, 2002, File No. 1-3164, as Exhibit 4.2(a), in Form 8-K dated November 20, 2002, File No. 1-3164, as Exhibit 4.2(a), in Form 8-K dated December 6, 2002, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated February 11, 2003, File No. 1-3164, as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated March 12, 2003, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated April 15, 2003, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated May 1, 2003, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated November 14, 2003, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated February 10, 2004, File No. 1-3164, as Exhibit 4.2 in Form 8-K dated April 7, 2004, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated August 19, 2004, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated November 9, 2004, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated March 8, 2005, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated January 11, 2006, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated January 13, 2006, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated February 1, 2006, File No. 1-3164, as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated March 9, 2006, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated June 7, 2006, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated January 30, 2007, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated April 4, 2007, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated October 11, 2007, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated December 4, 2007, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated May 8, 2008, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated November 14, 2008, File No. 1-3164 as Exhibit 4.2, in Form 8-K dated February 26, 2009, File No. 1-3164 as Exhibit 4.2, in Form 8-K dated September 27, 2010, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated March 3, 2011, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated May 18, 2011, File No. 1-3164, as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated January 10, 2012, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated October 9, 2012, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated November 27, 2012, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated December 3, 2013, File No. 1-3164, as Exhibit 4.2, and in Form 8-K dated August 20, 2014, File No. 1-3164, as Exhibit 4.6.)
(b)	3	—	Amended and Restated Trust Agreement of Alabama Power Capital Trust V dated as of September 1, 2002. (Designated in Form 8-K dated September 26, 2002, File No. 1-3164, as Exhibit 4.12-B.)
(b)	4	—	

Guarantee Agreement relating to Alabama Power Capital Trust V dated as of September 1, 2002. (Designated in Form 8-K dated September 26, 2002, File No. 1-3164, as Exhibit 4.16-B.)

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Georgia Power

(c)	1	—	Senior Note Indenture dated as of January 1, 1998, between Georgia Power and The Bank of New York Mellon (as successor to JPMorgan Chase Bank, N.A. (formerly known as The Chase Manhattan Bank)), as Trustee, and indentures supplemental thereto through August 16, 2013. (Designated in Form 8-K dated January 21, 1998, File No. 1-6468, as Exhibits 4.1 and 4.2, in Forms 8-K each dated November 19, 1998, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated March 3, 1999, File No. 1-6469 as Exhibit 4.2, in Form 8-K dated February 15, 2000, File No. 1-6469 as Exhibit 4.2, in Form 8-K dated January 26, 2001, File No. 1-6469 as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated February 16, 2001, File No. 1-6469 as Exhibit 4.2, in Form 8-K dated May 1, 2001, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated June 27, 2002, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated November 15, 2002, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated February 13, 2003, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated February 21, 2003, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated April 10, 2003, File No. 1-6468, as Exhibits 4.1, 4.2 and 4.3, in Form 8-K dated September 8, 2003, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated September 23, 2003, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated January 12, 2004, File No. 1-6468, as Exhibits 4.1 and 4.2, in Form 8-K dated February 12, 2004, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated August 11, 2004, File No. 1-6468, as Exhibits 4.1 and 4.2, in Form 8-K dated January 13, 2005, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated April 12, 2005, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated November 30, 2005, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated December 8, 2006, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated March 6, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated June 4, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated June 18, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated July 10, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated August 24, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated November 29, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated March 12, 2008, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated June 5, 2008, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated November 12, 2008, File No. 1-6468, as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated February 4, 2009, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated December 8, 2009, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated March 9, 2010, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated May 24, 2010, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated August 26, 2010, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated September 20, 2010, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated January 13, 2011, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated April 12, 2011, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated February 29, 2012, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated May 8, 2012, File No. 1-6468, as Exhibit 4.2(b), in Form 8-K dated August 7, 2012, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated November 8, 2012, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated March 12, 2013, File No. 1-6468, as Exhibits 4.2(a) and 4.2(b), and in Form 8-K dated August 12, 2013, File No. 1-6468, as Exhibit 4.2.)
(c)	2	—	Loan Guarantee Agreement between Georgia Power and the DOE dated as of February 20, 2014. (Designated in Form 8-K dated February 20, 2014, File No. 1-6468, as Exhibit 4.1.)
(c)	3	—	Note Purchase Agreement among Georgia Power, the DOE, and the Federal Financing Bank dated as of February 20, 2014. (Designated in Form 8-K dated February 20, 2014, File No. 1-6468, as Exhibit 4.2.)

(c)	4	—	Future Advance Promissory Note dated February 20, 2014 made by Georgia Power to the FFB. (Designated in Form 8-K dated February 20, 2014, File No. 1-6468, as Exhibit 4.3.)
(c)	5	—	Deed to Secure Debt, Security Agreement and Fixture Filing between Georgia Power and PNC Bank, National Association, doing business as Midland Loan Services Inc., a division of PNC Bank, National Association dated as of February 20, 2014. (Designated in Form 8-K dated February 20, 2014, File No. 1-6468, as Exhibit 4.4.)
(c)	6	—	Owners Consent to Assignment and Direct Agreement and Amendment to Plant Alvin W. Vogtle Additional Units Ownership Participation Agreement by and among Georgia Power, OPC, MEAG Power, and Dalton dated as of February 20, 2014. (Designated in Form 8-K dated February 20, 2014, File No. 1-6468, as Exhibit 4.5.)

Gulf Power

(d)	1	—	Senior Note Indenture dated as of January 1, 1998, between Gulf Power and The Bank of New York Mellon (as successor to JPMorgan Chase Bank, N.A. (formerly known as The Chase Manhattan Bank)), as Trustee, and indentures supplemental thereto through September 23, 2014. (Designated in Form 8-K dated June 17, 1998, File No. 0-2429, as Exhibits 4.1 and 4.2, in Form 8-K dated August 17, 1999, File No. 0-2429, as Exhibit 4.2, in Form 8-K dated July 31, 2001, File No. 0-2429, as Exhibit 4.2, in Form 8-K dated October 5, 2001, File No. 0-2429, as Exhibit 4.2, in Form 8-K dated January 18, 2002, File No. 0-2429, as Exhibit 4.2, in Form 8-K dated March 21, 2003, File No. 0-2429, as Exhibit 4.2, in Form 8-K dated July 10, 2003, File No. 001-31737, as Exhibits 4.1 and 4.2, in Form 8-K dated September 5, 2003, File No. 001-31737, as Exhibit 4.1, in Form 8-K dated April 6, 2004, File No. 001-31737, as Exhibit 4.1, in Form 8-K dated September 13, 2004, File No. 001-31737, as Exhibit 4.1, in Form 8-K dated August 11, 2005, File No. 001-31737, as Exhibit 4.1, in Form 8-K dated October 27, 2005, File No. 001-31737, as Exhibit 4.1, in Form 8-K dated November 28, 2006, File No. 001-31737, as Exhibit 4.2, in Form 8-K dated June 5, 2007, File No. 001-31737, as Exhibit 4.2, in Form 8-K dated June 22, 2009, File No. 001-31737, as Exhibit 4.2, in Form 8-K dated April 6, 2010, File No. 001-31737, as Exhibit 4.2, in Form 8-K dated September 9, 2010, File No. 001-31737, as Exhibit 4.2, in Form 8-K dated May 12, 2011, File No. 001-31737, as Exhibit 4.2, in Form 8-K dated May 15, 2012, File No. 001-31737, as Exhibit 4.2, in Form 8-K dated June 10, 2013, File No. 001-31737, as Exhibit 4.2, and in Form 8-K dated September 16, 2014, File No. 001-31737, as Exhibit 4.2.)

Mississippi Power

(e)	1	—	Senior Note Indenture dated as of May 1, 1998 between Mississippi Power and Wells Fargo Bank, National Association, as Successor Trustee, and indentures supplemental thereto through March 9, 2012. (Designated in Form 8-K dated May 14, 1998, File No. 001-11229, as Exhibits 4.1, 4.2(a) and 4.2(b), in Form 8-K dated March 22, 2000, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated March 12, 2002, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated April 24, 2003, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated March 3, 2004, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated June 24, 2005, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated November 8, 2007, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated November 14, 2008, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated March 3, 2009, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated October 11, 2011, File No. 001-11229, as Exhibits 4.2(a) and 4.2(b), and in Form 8-K dated March 5, 2012, File No. 001-11229, as Exhibit 4.2(b).)

Southern Power

(f)	1	—	Senior Note Indenture dated as of June 1, 2002, between Southern Power Company and The Bank of New York Mellon (formerly known as The Bank of New York), as Trustee, and indentures supplemental thereto through July 16, 2013. (Designated in Registration No. 333-98553 as Exhibits 4.1 and 4.2 and in Southern Power Company's Form 10-Q for the quarter ended June 30, 2003, File No. 333-98553, as Exhibit 4(g)1, in Form 8-K dated November 13, 2006, File No. 333-98553, as Exhibit 4.2, in Form 8-K dated September 14, 2011, File No. 333-98553, as Exhibit 4.4, and in Form 8-K dated July 10, 2013, File No. 333-98553, as Exhibit 4.4.)

(10) Material Contracts

Southern Company

#	(a)	1	—	Southern Company 2011 Omnibus Incentive Compensation Plan, effective May 25, 2011. (Designated in Southern Company's Form 8-K dated May 25, 2011, File No. 1-3526, as Exhibit 10.1.)
#	(a)	2	—	Form of Stock Option Award Agreement for Executive Officers of Southern Company under the Southern Company Omnibus Incentive Compensation Plan. (Designated in Southern Company's Form 10-Q for the quarter ended March 31, 2011, File No. 1-3526, as Exhibit 10(a)3.)
#	(a)	3	—	Deferred Compensation Plan for Outside Directors of The Southern Company, Amended and Restated effective January 1, 2008. (Designated in Southern Company's Form 10-K for the year ended December 31, 2007, File No. 1-3526, as Exhibit 10(a)3.)
#	(a)	4	—	Southern Company Deferred Compensation Plan as amended and restated as of January 1, 2009 and First Amendment thereto effective January 1, 2010. (Designated in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)4 and in Southern Company's Form 10-K for the year ended December 31, 2009, File No. 1-3526, as Exhibit 10(a)5.)

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#	(a)	5	—	The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective January 1, 2009 and First Amendment thereto effective January 1, 2010. (Designated in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)6 and in Southern Company's Form 10-K for the year ended December 31, 2009, File No. 1-3526, as Exhibit 10(a)(8).)
#	(a)	6	—	The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of January 1, 2009 and First Amendment thereto effective January 1, 2010. (Designated in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)7 and in Southern Company's Form 10-K for the year ended December 31, 2009, File No. 1-3526, as Exhibit 10(a)10.)
#	(a)	7	—	Retention and Restricted Stock Unit Award Agreement by and between Southern Company and Charles D. McCrary effective May 22, 2012. (Designated in Southern Company's Form 10-Q for the quarter ended June 30, 2012, File No. 1-3526, as Exhibit 10(a)1.)
#	(a)	8	—	Amendment to Retention and Restricted Stock Unit Award Agreement by and between Southern Company and Charles D. McCrary effective February 10, 2014. (Designated in Southern Company's Form 10-K for the year ended December 31, 2013, File No. 1-3526, as Exhibit 10(a)9.)
#	(a)	9	—	The Southern Company Change in Control Benefits Protection Plan, effective December 31, 2008. (Designated in Form 8-K dated December 31, 2008, File No. 1-3526, as Exhibit 10.1.)
#	(a)	10	—	Southern Company Deferred Compensation Trust Agreement as amended and restated effective January 1, 2001 between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, SouthernLINC Wireless, Southern Company Energy Solutions, LLC, and Southern Nuclear and First Amendment thereto effective January 1, 2009. (Designated in Southern Company's Form 10-K for the year ended December 31, 2000, File No. 1-3526, as Exhibit 10(a)103 and in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)16.)
#	(a)	11	—	Deferred Stock Trust Agreement for Directors of Southern Company and its subsidiaries, dated as of January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. (Designated in Southern Company's Form 10-K for the year ended December 31, 2000, File No. 1-3526, as Exhibit 10(a)104 and in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)18.)
#	(a)	12	—	Amended and Restated Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its subsidiaries, effective September 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. (Designated in Southern Company's Form 10-K for the year ended December 31, 2001, File No. 1-3526, as Exhibit 10(a)92 and in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)20.)
#	(a)	13	—	Amended and Restated Southern Company Senior Executive Change in Control Severance Plan effective December 31, 2008, First Amendment thereto effective January 1, 2010, and Second Amendment thereto effective February 23, 2011. (Designated in Southern Company's Form 10-K for the year ended December 31, 2008,

				File No. 1-3526, as Exhibit 10(a)23, in Southern Company's Form 10-K for the year ended December 31, 2009, File No. 1-3526, as Exhibit 10(a)22, and in Southern Company's Form 10-K for the year ended December 31, 2010, File No. 1-3526, as Exhibit 10(a)16.)
#	(a)	14	—	Southern Company Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008 and First Amendment thereto effective January 1, 2010. (Designated in Southern Company's Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)24 and in Southern Company's Form 10-K for the year ended December 31, 2009, File No. 1-3526, as Exhibit 10(a)24.)
# *	(a)	15	—	Base Salaries of Named Executive Officers.
#	(a)	16	—	Summary of Non-Employee Director Compensation Arrangements. (Designated in Form 8-K dated February 10, 2014, File No. 1-3526, as Exhibit 10.1.)
# *	(a)	17	—	Form of Terms for Performance Share Awards granted under the Southern Company 2011 Omnibus Incentive Compensation Plan.
#	(a)	18	—	Retention and Restricted Stock Unit Award Agreement between Southern Nuclear and Stephen E. Kuczynski effective as of July 11, 2011. (Designated in Form 10-Q for the quarter ended March 31, 2013, File No. 1-3526, as Exhibit 10(a)3).)

Alabama Power

	(b)	1	—	Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power Company, and SCS. (Designated in Form 10-Q for the quarter ended March 31, 2007, File No. 1-3164, as Exhibit 10(b)5.)
#	(b)	2	—	Southern Company 2011 Omnibus Incentive Compensation Plan, effective May 25, 2011. See Exhibit 10(a)1 herein.
#	(b)	3	—	Form of Stock Option Award Agreement for Executive Officers of Southern Company under the Southern Company Omnibus Incentive Compensation Plan. See Exhibit 10(a)2 herein.
#	(b)	4	—	Southern Company Deferred Compensation Plan as amended and restated as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)4 herein.
#	(b)	5	—	The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)5 herein.
#	(b)	6	—	The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)6 herein.
#	(b)	7	—	Southern Company Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)14 herein.
#	(b)	8	—	Deferred Compensation Plan for Directors of Alabama Power Company, Amended and Restated effective January 1, 2008. (Designated in Alabama Power's Form 10-Q for the quarter ended June 30, 2008, File No. 1-3164, as Exhibit 10(b)1.)
#	(b)	9	—	The Southern Company Change in Control Benefits Protection Plan, effective December 31, 2008. See Exhibit 10(a)9 herein.
#	(b)	10	—	Southern Company Deferred Compensation Trust Agreement as amended and restated effective January 1, 2001 between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, SouthernLINC Wireless, Southern Company Energy Solutions, LLC, and Southern Nuclear and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)10 herein.
#	(b)	11	—	Deferred Stock Trust Agreement for Directors of Southern Company and its subsidiaries, dated as of January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)11 herein.
#	(b)	12	—	Amended and Restated Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its subsidiaries, effective September 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)12 herein.
#	(b)	13	—	Amended and Restated Southern Company Senior Executive Change in Control Severance Plan effective December 31, 2008, First Amendment thereto effective January 1, 2010, and Second Amendment thereto effective February 23, 2011. See Exhibit 10(a)13 herein.
# *	(b)	14	—	Base Salaries of Named Executive Officers.
#	(b)	15	—	

				Summary of Non-Employee Director Compensation Arrangements. (Designated in Alabama Power's Form 10-Q for the quarter ended June 30, 2010, File No. 1-3164, as Exhibit 10(b)1.)
#	(b)	16	—	Form of Terms for Performance Share Awards granted under the Southern Company 2011 Omnibus Incentive Compensation Plan. See Exhibit 10(a)17 herein.
#	(b)	17	—	Deferred Compensation Agreement between Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and SCS and Philip C. Raymond dated September 15, 2010. (Designated in Alabama Power's Form 10-Q for the quarter ended September 30, 2010, File No. 1-3164, as Exhibit 10(b)2.)
#	(b)	18	—	Retention and Restricted Stock Unit Award Agreement by and between Southern Company and Charles D. McCrary effective May 22, 2012. See Exhibit 10(a)7 herein.
#	(b)	19	—	Amendment to Retention and Restricted Stock Unit Award Agreement by and between Southern Company and Charles D. McCrary effective February 10, 2014. See Exhibit 10(a)8 herein.

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#	(b)	20	—	Retention Award Agreement between Alabama Power and Steven R. Spencer effective July 15, 2013. (Designated in Form 10-Q for the quarter ended September 30, 2013, File No. 1-3164, as Exhibit 10(b)1.)
Georgia Power				
	(c)	1	—	Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power Company, and SCS. See Exhibit 10(b)1 herein.
	(c)	2	—	Revised and Restated Integrated Transmission System Agreement dated as of November 12, 1990, between Georgia Power and OPC. (Designated in Georgia Power's Form 10-K for the year ended December 31, 1990, File No. 1-6468, as Exhibit 10(g).)
	(c)	3	—	Revised and Restated Integrated Transmission System Agreement between Georgia Power and Dalton dated as of December 7, 1990. (Designated in Georgia Power's Form 10-K for the year ended December 31, 1990, File No. 1-6468, as Exhibit 10(gg).)
	(c)	4	—	Revised and Restated Integrated Transmission System Agreement between Georgia Power and MEAG Power dated as of December 7, 1990. (Designated in Georgia Power's Form 10-K for the year ended December 31, 1990, File No. 1-6468, as Exhibit 10(hh).)
#	(c)	5	—	Southern Company 2011 Omnibus Incentive Compensation Plan, effective May 25, 2011. See Exhibit 10(a)1 herein.
#	(c)	6	—	Form of Stock Option Award Agreement for Executive Officers of Southern Company under the Southern Company Omnibus Incentive Compensation Plan. See Exhibit 10(a)2 herein.
#	(c)	7	—	Southern Company Deferred Compensation Plan as amended and restated as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)4 herein.
#	(c)	8	—	The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)5 herein.
#	(c)	9	—	The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)6 herein.
#	(c)	10	—	Southern Company Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)14 herein.
#	(c)	11	—	Deferred Compensation Plan For Directors of Georgia Power Company, Amended and Restated Effective January 1, 2008. (Designated in Form 10-K for the year ended December 31, 2007, File No. 1-6468, as Exhibit 10(c)12.)
#	(c)	12	—	The Southern Company Change in Control Benefits Protection Plan, effective December 31, 2008. See Exhibit 10(a)9 herein.
#	(c)	13	—	Southern Company Deferred Compensation Trust Agreement as amended and restated effective January 1, 2001 between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, SouthernLINC Wireless, Southern Company Energy Solutions, LLC, and Southern Nuclear and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)10 herein.
#	(c)	14	—	Deferred Stock Trust Agreement for Directors of Southern Company and its subsidiaries, dated as of January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)11 herein.

#	(c)	15	—	Amended and Restated Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its subsidiaries, effective September 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)12 herein.
#	(c)	16	—	Amended and Restated Southern Company Senior Executive Change in Control Severance Plan effective December 31, 2008, First Amendment thereto effective January 1, 2010, and Second Amendment thereto effective February 23, 2011. See Exhibit 10(a)13 herein.
# *	(c)	17	—	Base Salaries of Named Executive Officers.
#	(c)	18	—	Summary of Non-Employee Director Compensation Arrangements. (Designated in Georgia Power's Form 10-K for the year ended December 31, 2009, File No. 1-6468, as Exhibit 10(c)26.)

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	(c)	19	—	Engineering, Procurement and Construction Agreement, dated as of April 8, 2008, between Georgia Power, for itself and as agent for OPC, MEAG Power, and Dalton, as owners, and a consortium consisting of Westinghouse Electric Company LLC and Stone & Webster, Inc., as contractor, for Units 3 & 4 at the Vogtle Electric Generating Plant Site, Amendment No. 1 thereto dated as of December 11, 2009, Amendment No. 2 thereto dated as of January 15, 2010, Amendment No. 3 thereto dated as of February 23, 2010, Amendment No. 4 thereto dated as of May 2, 2011, Amendment No. 5 thereto dated as of February 7, 2012, and Amendment No. 6 thereto dated as of January 23, 2014. (Georgia Power requested confidential treatment for certain portions of these documents pursuant to applications for confidential treatment sent to the SEC. Georgia Power omitted such portions from the filings and filed them separately with the SEC.) (Designated in Form 10-Q/A for the quarter ended June 30, 2008, File No. 1-6468, as Exhibit 10(c)1, in Form 10-K for the year ended December 31, 2009, File No. 1-6468, as Exhibit 10(c)29, in Georgia Power's Form 10-Q for the quarter ended March 31, 2010, File No. 1-6468, as Exhibits 10(c)1 and 10(c)2, in Georgia Power's Form 10-Q for the quarter ended June 30, 2011, File No. 1-6468, as Exhibit 10(c)2, in Georgia Power's Form 10-Q for the quarter ended March 31, 2012, File No. 1-6468, as Exhibit 10(c)2, and in Georgia Power's Form 10-Q for the quarter ended March 31, 2014, File No. 1-6468, as Exhibit 10(c)2.)
#	(c)	20	—	Form of Terms for Performance Share Awards granted under the Southern Company 2011 Omnibus Incentive Compensation Plan. See Exhibit 10(a)17 herein.
#	(c)	21	—	Retention Award Agreement and Amendment thereto between Southern Nuclear and Joseph A. Miller, effective January 1, 2013. (Designated in Form 10-K for the year ended December 31, 2012, File No. 1-6468, as Exhibits 10(c)24 and 10(c)25.)

Gulf Power

	(d)	1	—	Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power Company, and SCS. See Exhibit 10(b)1 herein.
#	(d)	2	—	Southern Company 2011 Omnibus Incentive Compensation Plan, effective May 25, 2011. See Exhibit 10(a)1 herein.
#	(d)	3	—	Form of Stock Option Award Agreement for Executive Officers of Southern Company under the Southern Company Omnibus Incentive Compensation Plan. See Exhibit 10(a)2 herein.
#	(d)	4	—	Southern Company Deferred Compensation Plan as amended and restated as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)4 herein.
#	(d)	5	—	The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)6 herein.
#	(d)	6	—	Southern Company Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)14 herein.
#	(d)	7	—	The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)5 herein.
#	(d)	8	—	Deferred Compensation Plan For Outside Directors of Gulf Power Company, Amended and Restated effective January 1, 2008. (Designated in Gulf Power's Form 10-Q for the

				quarter ended March 31, 2008, File No. 0-2429, as Exhibit 10(d)1.)
#	(d)	9	—	The Southern Company Change in Control Benefits Protection Plan, effective December 31, 2008. See Exhibit 10(a)9 herein.
#	(d)	10	—	Southern Company Deferred Compensation Trust Agreement as amended and restated effective January 1, 2001 between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, SouthernLINC Wireless, Southern Company Energy Solutions, LLC, and Southern Nuclear and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)10 herein.
#	(d)	11	—	Deferred Stock Trust Agreement for Directors of Southern Company and its subsidiaries, dated as of January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)11 herein.

#	(d)	12	—	Amended and Restated Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its subsidiaries, effective September 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)12 herein.
#	(d)	13	—	Amended and Restated Southern Company Senior Executive Change in Control Severance Plan effective December 31, 2008, First Amendment thereto effective January 1, 2010, and Second Amendment thereto effective February 23, 2011. See Exhibit 10(a)13 herein.
# *	(d)	14	—	Base Salaries of Named Executive Officers.
#	(d)	15	—	Summary of Non-Employee Director Compensation Arrangements. (Designated in Gulf Power's Form 10-Q for the quarter ended June 30, 2010, File No. 001-31737, as Exhibit 10(d)1.)
#	(d)	16	—	Form of Terms for Performance Share Awards granted under the Southern Company 2011 Omnibus Incentive Compensation Plan. See Exhibit 10(a)17 herein.
#	(d)	17	—	Deferred Compensation Agreement between Southern Company, Georgia Power, Gulf Power, and Southern Nuclear and Bentina C. Terry dated August 1, 2010. (Designated in Gulf Power's Form 10-Q for the quarter ended September 30, 2010, File No. 001-31737, as Exhibit 10(d)2.)
#	(d)	18	—	Separation and Release Agreement between P. Bernard Jacob and Gulf Power effective May 2, 2014. (Designated in Gulf Power's Form 10-Q for the quarter ended June 30, 2014, File No. 001-31737, as Exhibit 10(d)1.)
Mississippi Power				
	(e)	1	—	Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power Company, and SCS. See Exhibit 10(b)1 herein.
	(e)	2	—	Transmission Facilities Agreement dated February 25, 1982, Amendment No. 1 dated May 12, 1982 and Amendment No. 2 dated December 6, 1983, between Entergy Corporation (formerly Gulf States) and Mississippi Power. (Designated in Mississippi Power's Form 10-K for the year ended December 31, 1981, File No. 001-11229, as Exhibit 10(f), in Mississippi Power's Form 10-K for the year ended December 31, 1982, File No. 001-11229, as Exhibit 10(f)(2), and in Mississippi Power's Form 10-K for the year ended December 31, 1983, File No. 001-11229, as Exhibit 10(f)(3).)
#	(e)	3	—	Southern Company 2011 Omnibus Incentive Compensation Plan, effective May 25, 2011. See Exhibit 10(a)1 herein.
#	(e)	4	—	Form of Stock Option Award Agreement for Executive Officers of Southern Company under the Southern Company Omnibus Incentive Compensation Plan. See Exhibit 10(a)2 herein.
#	(e)	5	—	Southern Company Deferred Compensation Plan as amended and restated as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)4 herein.
#	(e)	6	—	The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)6 herein.
#	(e)	7	—	Southern Company Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)14 herein.
#	(e)	8	—	

				The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective January 1, 2009 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)5 herein.
#	(e)	9	—	Deferred Compensation Plan for Outside Directors of Mississippi Power Company, Amended and Restated effective January 1, 2008. (Designated in Mississippi Power's Form 10-Q for the quarter ended March 31, 2008, File No. 001-11229 as Exhibit 10(e)1.)
#	(e)	10	—	The Southern Company Change in Control Benefits Protection Plan, effective December 31, 2008. See Exhibit 10(a)9 herein.
#	(e)	11	—	Southern Company Deferred Compensation Trust Agreement as amended and restated effective January 1, 2001 between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, SouthernLINC Wireless, Southern Company Energy Solutions, LLC, and Southern Nuclear and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)10 herein.

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	#	(e)	12	—	Deferred Stock Trust Agreement for Directors of Southern Company and its subsidiaries, dated as of January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)11 herein.
	#	(e)	13	—	Amended and Restated Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its subsidiaries, effective September 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)12 herein.
	#	(e)	14	—	Amended and Restated Southern Company Senior Executive Change in Control Severance Plan effective December 31, 2008, First Amendment thereto effective January 1, 2010, and Second Amendment thereto effective February 23, 2011. See Exhibit 10(a)13 herein.
	# *	(e)	15	—	Base Salaries of Named Executive Officers.
	#	(e)	16	—	Summary of Non-Employee Director Compensation Arrangements. (Designated in Mississippi Power's Form 10-K for the year ended December 31, 2009, File No. 001-11229, as Exhibit 10(e)22.)
		(e)	17	—	Cooperative Agreement between the DOE and SCS dated as of December 12, 2008. (Designated in Mississippi Power's Form 10-K for the year ended December 31, 2008, File No. 001-11229, as Exhibit 10(e)22.) (Mississippi Power requested confidential treatment for certain portions of this document pursuant to an application for confidential treatment sent to the SEC. Mississippi Power omitted such portions from this filing and filed them separately with the SEC.)
	#	(e)	18	—	Form of Terms for Performance Share Awards granted under the Southern Company 2011 Omnibus Incentive Compensation Plan. See Exhibit 10(a)17 herein.
	#	(e)	19	—	Consulting Agreement between Mississippi Power and Edward Day, VI effective May 20, 2013. (Designated in Form 10-Q for the quarter ended June 30, 2013, File No. 001-11229, as Exhibit 10(e)1.)
	#	(e)	20	—	Amended Deferred Compensation Agreement, effective December 31, 2008 between Southern Company, SCS, Georgia Power, Gulf Power and G. Edison Holland, Jr. (Designated in Form 10-Q for the quarter ended March 31, 2011, File No. 001-11229, as Exhibit 10(a)2.)
	Southern Power				
		(f)	1	—	Service contract dated as of January 1, 2001, between SCS and Southern Power Company. (Designated in Southern Company's Form 10-K for the year ended December 31, 2001, File No. 1-3526, as Exhibit 10(a)(2).)
		(f)	2	—	Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power Company, and SCS. See Exhibit 10(b)1 herein.
(14)	Code of Ethics				
	Southern Company				
		(a)		—	The Southern Company Code of Ethics. (Designated in Southern Company's Form 10-K for the year ended December 31, 2013, File No. 1-3526, as Exhibit 14(a).)
	Alabama Power				
		(b)		—	The Southern Company Code of Ethics. See Exhibit 14(a) herein.
	Georgia Power				
		(c)		—	The Southern Company Code of Ethics. See Exhibit 14(a) herein.
	Gulf Power				

(d)	—	The Southern Company Code of Ethics. See Exhibit 14(a) herein.
Mississippi Power		
(e)	—	The Southern Company Code of Ethics. See Exhibit 14(a) herein.
Southern Power		
(f)	—	The Southern Company Code of Ethics. See Exhibit 14(a) herein.

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(21) Subsidiaries of Registrants
Southern Company
* (a) — Subsidiaries of Registrant.
Alabama Power
(b) — Subsidiaries of Registrant. See Exhibit 21(a) herein.
Georgia Power
(c) — Subsidiaries of Registrant. See Exhibit 21(a) herein.
Gulf Power
(d) — Subsidiaries of Registrant. See Exhibit 21(a) herein.
Mississippi Power
(e) — Subsidiaries of Registrant. See Exhibit 21(a) herein.
Southern Power
Omitted pursuant to General Instruction I(2)(b) of Form 10-K.
(23) Consents of Experts and Counsel
Southern Company
* (a) 1 — Consent of Deloitte & Touche LLP.
Alabama Power
* (b) 1 — Consent of Deloitte & Touche LLP.
Georgia Power
* (c) 1 — Consent of Deloitte & Touche LLP.
Gulf Power
* (d) 1 — Consent of Deloitte & Touche LLP.
Mississippi Power
* (e) 1 — Consent of Deloitte & Touche LLP.
Southern Power
* (f) 1 — Consent of Deloitte & Touche LLP.
(24) Powers of Attorney and Resolutions
Southern Company
* (a) — Power of Attorney and resolution.
Alabama Power
* (b) — Power of Attorney and resolution.
Georgia Power
* (c) — Power of Attorney and resolution.
Gulf Power
* (d) — Power of Attorney and resolution.
Mississippi Power
* (e) — Power of Attorney and resolution.
Southern Power
* (f) — Power of Attorney and resolution.
(31) Section 302 Certifications
Southern Company
* (a) 1 — Certificate of Southern Company's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
* (a) 2 — Certificate of Southern Company's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
Alabama Power
* (b) 1 — Certificate of Alabama Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

*	(b)	2	—	Certificate of Alabama Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
Georgia Power				
*	(c)	1	—	Certificate of Georgia Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
*	(c)	2	—	Certificate of Georgia Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
Gulf Power				
*	(d)	1	—	Certificate of Gulf Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
*	(d)	2	—	Certificate of Gulf Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
Mississippi Power				
*	(e)	1	—	Certificate of Mississippi Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
*	(e)	2	—	Certificate of Mississippi Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
Southern Power				
*	(f)	1	—	Certificate of Southern Power Company's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
*	(f)	2	—	Certificate of Southern Power Company's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

(32) Section 906 Certifications

Southern Company			
*	(a)	—	Certificate of Southern Company's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.
Alabama Power			
*	(b)	—	Certificate of Alabama Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.
Georgia Power			
*	(c)	—	Certificate of Georgia Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.
Gulf Power			
*	(d)	—	Certificate of Gulf Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.
Mississippi Power			
*	(e)	—	Certificate of Mississippi Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.
Southern Power			
*	(f)	—	Certificate of Southern Power Company's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

(101) XBRL-Related Documents

*	INS	—	XBRL Instance Document
*	SCH	—	XBRL Taxonomy Extension Schema Document
*	CAL	—	XBRL Taxonomy Calculation Linkbase Document
*	DEF	—	XBRL Definition Linkbase Document
*	LAB	—	XBRL Taxonomy Label Linkbase Document
*	PRE	—	XBRL Taxonomy Presentation Linkbase Document

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