MISSISSIPPI POWER COMPANY

2015 ANNUAL REPORT

MISSISSIPPI POWER

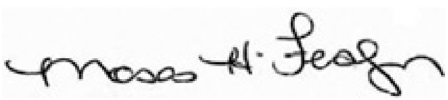
A SOUTHERN COMPANY

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Mississippi Power Company 2015 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, 2015.

Anthony L. Wilson
President and Chief Executive Officer



Moses H. Feagin
Vice President, Chief Financial Officer, and Treasurer

February 26, 2016

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, 2015 and 2014, 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, 2015. 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 39 to 85) present fairly, in all material respects, the financial position of Mississippi Power Company as of December 31, 2015 and 2014, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Atlanta, Georgia
February 26, 2016

DEFINITIONS

Term	Meaning
2012 MPSC CPCN Order	A detailed order issued by the Mississippi PSC in April 2012 confirming the CPCN originally approved by the Mississippi PSC in 2010 authorizing acquisition, construction, and operation of the Kemper IGCC
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	U.S. generally accepted accounting principles
Georgia Power	Georgia Power Company
Gulf Power	Gulf Power Company
IGCC	Integrated coal gasification combined cycle
IRS	Internal Revenue Service
ITC	Investment tax credit
Kemper IGCC	IGCC facility under construction 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

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
Southern Company	The Southern Company
Southern Company system	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
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 2015 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 operate in 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.

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 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 placed the combined cycle and the associated common facilities portion of the Kemper IGCC in-service in August 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 third quarter 2016.

The Company's current cost estimate for the Kemper IGCC in total is approximately $6.63 billion, which includes approximately $5.29 billion of costs subject to the construction cost cap. The Company does not intend to seek any rate recovery for any related costs that exceed the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions. The Company has recorded pre-tax charges to income for revisions to the cost estimate of $365 million ($226 million after tax), $868 million ($536 million after tax), and $1.1 billion ($681 million after tax) in 2015, 2014, and 2013, respectively. Since 2012, in the aggregate, the Company has incurred charges of $2.41 billion ($1.5 billion after tax) as a result of changes in the cost estimate above the cost cap for the Kemper IGCC through December 31, 2015. The current cost estimate includes costs through August 31, 2016.

During 2015, events related to the Kemper IGCC had a significant adverse impact on the Company’s financial condition. These events include (i) the termination by SMEPA in May 2015 of the APA between the Company and SMEPA, whereby SMEPA previously agreed to purchase a 15% undivided interest in the Kemper IGCC, and the Company's subsequent return of approximately $301 million, including interest, to SMEPA; (ii) the termination of Mirror CWIP rates in July 2015 and the refund of $371 million in Mirror CWIP rate collections, including carrying costs, in the fourth quarter 2015 as a result of the Mississippi Supreme Court's (Court) reversal of the Mississippi PSC's 2013 rate order authorizing the collection of $156 million annually in Mirror CWIP rates; and (iii) the required recapture in December 2015 of $235 million of Internal Revenue Code of 1986, as amended (Internal Revenue Code), Section 48A (Phase II) tax credits as a result of the extension of the expected in-service date for the Kemper IGCC. As a result of the termination of the Mirror CWIP rates, the Company submitted a filing to the Mississippi PSC requesting interim rates to collect approximately $159 million annually until a final rate decision could be made on the Company's request to recover costs associated with Kemper IGCC assets that had been placed in service. The Mississippi PSC approved the implementation of the requested interim rates in August 2015. Subsequently, on December 3, 2015, the Mississippi PSC issued an order (In-Service Asset Rate Order), based on a stipulation (the 2015 Stipulation) between the Company and the MPUS, authorizing the Company to replace the interim rates with rates that provide for the recovery of approximately $126 million annually related to Kemper IGCC assets previously placed in service. Further proceedings related to cost recovery for the Kemper IGCC are expected after the remainder of the Kemper IGCC is placed in service which is currently expected in the third quarter 2016. On February 25, 2016, Greenleaf CO2 Solutions, LLC filed a notice of appeal of the In-Service Asset Rate Order with the Court. The Company believes the appeal has no merit; however, an adverse outcome in this appeal could have a material impact on the Company’s results of operations, financial condition, and liquidity. The ultimate outcome of this matter cannot be determined at this time. See FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle" herein for additional information.

As of December 31, 2015, the Company's current liabilities exceeded current assets by approximately $1.3 billion primarily due to $900 million of bank term loans scheduled to mature on April 1, 2016, and $300 million in senior notes scheduled to mature on October 15, 2016. See FINANCIAL CONDITION AND LIQUIDITY – "Sources of Capital" herein and Note 6 to the financial statements for additional information. The Company expects to refinance its 2016 debt maturities with bank term loans. The Company intends to utilize operating cash flows and lines of credit (to the extent available) as well as loans and, under certain circumstances, equity contributions from Southern Company to fund the remainder of the Company's capital needs.

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 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 2015.

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 2015 fossil Peak Season EFOR of 0.76% 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 2015 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. See RESULTS OF OPERATIONS herein for information on the Company's financial performance.

Earnings

The Company's net loss after dividends on preferred stock was $8 million in 2015 compared to $329 million in 2014. The change in 2015 was primarily the result of lower pre-tax charges of $365 million ($226 million after tax) in 2015 compared to pre-tax charges of $868 million ($536 million after tax) in 2014 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 reduction in net loss was also related to an increase in retail base revenues, due to the implementation of rates for certain Kemper assets placed in service that became effective with the first billing cycle in September (on August 19), and a decrease in interest expense primarily due to the termination of SMEPA's agreement to purchase a portion of the Kemper IGCC, partially offset by increases in income taxes due to a reduced net loss. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information regarding the Kemper IGCC.

The Company's net loss after dividends on preferred stock was $329 million in 2014 compared to $477 million in 2013. The decreased net loss in 2014 was primarily the result of lower pre-tax charges of $868 million ($536 million after tax) in 2014 compared to pre-tax charges of $1.1 billion ($681 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.

RESULTS OF OPERATIONS

A condensed statement of operations follows:

	Amount	Increase (Decrease) from Prior Year	
	2015	**2015**	2014
		(in millions)	
Operating revenues	**$ 1,138**	**$ (105)**	$ 98
Fuel	**443**	**(131)**	83
Purchased power	**12**	**(31)**	(6)
Other operations and maintenance	**274**	**3**	18
Depreciation and amortization	**123**	**26**	6
Taxes other than income taxes	**94**	**15**	(2)
Estimated loss on Kemper IGCC	**365**	**(503)**	(234)
Total operating expenses	**1,311**	**(621)**	(135)
Operating income	**(173)**	**516**	233
Allowance for equity funds used during construction	**110**	**(26)**	14
Interest expense, net of amounts capitalized	**7**	**(38)**	9
Other income (expense), net	**(8)**	**6**	(7)
Income taxes (benefit)	**(72)**	**213**	83
Net income (loss)	**(6)**	**321**	148
Dividends on preferred stock	**2**	**—**	—
Net income (loss) after dividends on preferred stock	**$ (8)**	**$ 321**	$ 148

Operating Revenues

Operating revenues for 2015 were $1.1 billion, reflecting a $105 million decrease from 2014. Details of operating revenues were as follows:

	Amount	
	2015	2014
	(in millions)	
Retail — prior year	**$ 795**	$ 799
Estimated change resulting from —		
Rates and pricing	**61**	(12)
Sales growth (decline)	**(3)**	(1)
Weather	**(1)**	3
Fuel and other cost recovery	**(76)**	6
Retail — current year	**776**	795
Wholesale revenues —		
Non-affiliates	**270**	323
Affiliates	**76**	107
Total wholesale revenues	**346**	430
Other operating revenues	**16**	18
Total operating revenues	**$ 1,138**	$ 1,243
Percent change	**(8.4)%**	8.5%

Total retail revenues for 2015 decreased $19 million, or 2.4%, compared to 2014 primarily due to a lower fuel cost recovery. This decrease was partially offset by changes in rates and pricing of $61 million. Total retail revenues for 2014 decreased $5 million, or

0.6%, compared to 2013 primarily as a result of $10 million in revenues recorded in 2013 that were reversed in 2014 as a result of the 2015 Court decision.

Revenues associated with changes in rates and pricing increased in 2015 when compared to 2014, primarily due to $50 million of net revenues associated with the implementation of rates for the Kemper IGCC that began in August 2015. In addition, 2014 revenues included the reversal of $11 million for 2013 as a result of the 2015 Court decision.

See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs" for additional information. 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. 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. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Fuel Cost Recovery" herein for additional information.

Wholesale revenues from power sales to non-affiliated utilities, including FERC-regulated MRA sales as well as market-based sales, were as follows:

	2015	2014	2013
		(in millions)	
Capacity and other	**$ 158**	$ 160	$ 143
Energy	**112**	163	151
Total non-affiliated	**$ 270**	$ 323	$ 294

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 21.0% of the Company’s total operating revenues in 2015 and are largely subject to rolling 10-year cancellation notices. Historically, these wholesale customers have acted as a group and any changes in contractual relationships for one customer are likely to be followed by the other wholesale customers.

Wholesale revenues from sales to non-affiliates decreased $53 million, or 16.4%, in 2015 compared to 2014 primarily as a result of a $51 million decrease in energy revenues, of which $13 million was associated with a decrease in KWH sales and $38 million was associated with lower fuel prices. Wholesale revenues from sales to non-affiliates increased $29 million, or 9.8%, in 2014 compared to 2013 as a result of a $17 million increase in base revenues primarily resulting from wholesale base rate increases effective April 1, 2013 and May 1, 2014 and a $12 million increase in energy revenues, of which $10 million was associated with an increase in KWH sales and $2 million was associated with higher fuel prices.

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 decreased $31 million, or 29.0%, in 2015 compared to 2014 primarily due to a $31 million decrease in energy revenues of which $28 million was associated with lower prices and $3 million was associated with a decrease in KWH sales. Wholesale revenues from sales to affiliates increased $72 million, or 208.3%, in 2014 compared to 2013 primarily due to a $75 million increase in energy revenues of which $69 million was associated with an increase in KWH sales and $5 million was associated with higher prices, partially offset by a decrease in capacity revenues of $2 million.

Energy Sales

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

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2015	**2015**	2014	**2015***	2014
	(in millions)				
Residential	**2,025**	**(4.8)%**	1.8%	**(0.4)%**	(2.3)%
Commercial	**2,806**	**(1.9)**	(0.2)	**(0.4)**	0.1
Industrial	**4,958**	**0.3**	4.3	**0.8**	4.3
Other	**40**	**(2.1)**	1.1	**(2.1)**	1.1
Total retail	**9,829**	**(1.4)**	2.4	**0.2 %**	1.6 %
Wholesale					
Non-affiliated	**3,852**	**(8.1)**	6.7		
Affiliated	**2,807**	**(3.2)**	211.4		
Total wholesale	**6,659**	**(6.1)**	45.9		
Total energy sales	**16,488**	**(3.4)%**	16.9%		

* In the first quarter 2015, the Company updated the methodology to estimate the unbilled revenue allocation among customer classes. This change did not have a significant impact on net income. The KWH sales variances in the above table reflect an adjustment to the estimated allocation of the Company's unbilled 2014 KWH sales among customer classes that is consistent with the actual allocation in 2015. Without this adjustment, 2015 weather-adjusted residential sales decreased 1.8%, commercial sales decreased 2.1% and industrial KWH sales increased 0.3% as compared to the corresponding period in 2014.

Changes in retail energy sales are generally the result of changes in electricity usage by customers, changes in weather, and changes in the number of customers. Retail energy sales decreased 1.4% in 2015 as compared to the prior year. This decrease was primarily the result of milder weather in the first and fourth quarters of 2015 as compared to the corresponding periods in 2014. Weather-adjusted residential and commercial KWH sales decreased primarily due to decreased customer usage partially offset by customer growth. Household income, one of the primary drivers of residential customer usage, had modest growth in 2015. The increase in industrial KWH energy sales was primarily due to expanded operation by many industrial customers.

Retail energy sales increased 2.4% in 2014 as compared to the prior year. This increase was primarily the result of colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013 and customer growth, partially offset by a decrease in customer usage. The increase in industrial KWH energy sales was primarily due to increased production related to expanded operation by many industrial customers. Weather-adjusted residential KWH 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.

Wholesale energy sales to non-affiliates decreased in 2015 compared to 2014 primarily due to decreased opportunity sales to the external market based on lower demand which was offset by lower system prices. Wholesale energy sales to non-affiliates increased in 2014 compared to 2013 primarily due to increased opportunity sales to the external market as a result of lower system prices.

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

Wholesale energy sales to affiliates decreased in 2015 compared to 2014 primarily due to lower fuel cost and less sales to affiliate companies. Wholesale energy sales to affiliates increased 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.

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:

	2015	2014	2013
Total generation *(millions of KWHs)*	**17,014**	16,881	13,721
Total purchased power *(millions of KWHs)*	**539**	886	1,559
Sources of generation *(percent)* –			
Coal	**17**	42	36
Gas	**83**	58	64
Cost of fuel, generated *(cents per net KWH)* –			
Coal	**3.71**	3.96	4.97
Gas	**2.58**	3.37	3.16
Average cost of fuel, generated *(cents per net KWH)*	**2.78**	3.64	3.87
Average cost of purchased power *(cents per net KWH)*	**2.17**	4.85	3.10

Fuel and purchased power expenses were $455 million in 2015, a decrease of $162 million, or 26.3%, as compared to the prior year. The decrease was primarily due to a $125 million decrease in the cost of fuel and purchased power and a decrease of $183 million in KWHs generated by coal generation and purchased power, partially offset by a $146 million increase in KWHs generated by gas generation. Fuel and purchased power expenses were $617 million in 2014, an increase of $77 million, or 14.3%, as compared to the prior year. The increase was primarily due to a $114 million increase in the total volume of KWHs generated, offset by a $37 million decrease 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" herein and Note 1 to the financial statements under "Fuel Costs" for additional information.

Fuel

Fuel expense decreased $131 million, or 22.8%, in 2015 compared to 2014. The decrease was the result of a 23.6% decrease in the average cost of fuel per KWH generated, partially offset by a 0.9% increase in the volume of KWH generated in 2015. Fuel expense increased $83 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.

Purchased Power - Non-Affiliates

Purchased power expense from non-affiliates decreased $13 million, or 72.2%, in 2015 compared to 2014. The decrease was primarily the result of a 72.4% decrease in the average cost per KWH purchased. Purchased power expense from non-affiliates increased $12 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. The increase in the average cost per KWH purchased was due to a higher marginal cost of fuel.

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 $18 million, or 72.0%, in 2015 compared to 2014. The decrease in 2015 was primarily the result of a 58.3% decrease in the volume of KWHs purchased and a 36.9% decrease in the average cost per KWH purchased compared to 2014. Purchased power expense from affiliates decreased $18 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.

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 $3 million, or 1.1%, in 2015 compared to the prior year. The increase was primarily related to a $7 million increase in employee compensation and benefits, including pension costs and a $6 million increase in generation maintenance expenses related to the combined cycle and the associated common facilities portion of the Kemper IGCC. See Note 2 to the financial statements for additional information on pension costs. Beginning in the third quarter 2015, in connection with the implementation of interim rates associated with the Kemper IGCC, the Company began expensing certain ongoing project costs associated with Kemper IGCC assets placed in service that previously were deferred as regulatory assets. See FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs – 2015 Rate Case" and "–Regulatory Assets and Liabilities" herein for additional information. These increases in 2015 were partially offset by decreases of $4 million in transmission and distribution expenses primarily related to overhead line maintenance and vegetation management, $3 million in generation maintenance expenses primarily due to lower outage costs, and $2 million in overtime labor.

Other operations and maintenance expenses increased $18 million, or 6.8%, in 2014 compared to 2013 primarily due to a $14 million increase in employee compensation and benefit expenses and a $7 million increase in generation maintenance expenses. These increases in 2014 were partially offset by a $2 million decrease in transmission expenses primarily related to overhead line maintenance and vegetation management, and a $1 million decrease in customer accounting expenses primarily due to uncollectibles.

Depreciation and Amortization

Depreciation and amortization increased $26 million, or 26.8%, in 2015 compared to 2014 primarily due to an $18 million increase in depreciation related to an increase in assets in service and an increase in the depreciation rates, a $16 million increase due to amortization of regulatory assets associated with the Kemper IGCC, and a $2 million increase resulting from the estimated 2015 cost of capital as agreed in the In-Service Asset Rate Order. These increases were partially offset by decreases of $5 million in ECO plan amortization, $3 million in Kemper combined cycle cost deferrals, and $2 million in deferrals associated with the purchase of Plant Daniel Units 3 and 4. See FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs – Regulatory Assets and Liabilities" herein for additional information.

Depreciation and amortization increased $6 million, or 6.3%, in 2014 compared to 2013 primarily due to a $4 million increase related to the reversal of a regulatory deferral associated with the Kemper IGCC municipal franchise taxes, a $2 million increase in depreciation related to an increase in assets in service, and a $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 $4 million decrease associated with a wholesale revenue requirement adjustment.

See Note 1 to the financial statements under "Depreciation and Amortization" and Note 3 to the financial statements under "FERC Matters" and " – Environmental Compliance Overview Plan" for additional information.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $15 million, or 19.0%, in 2015 compared to 2014 primarily as a result of a $12 million increase in ad valorem taxes and a $4 million increase in franchise taxes, partially offset by a $1 million decrease in payroll taxes. Taxes other than income taxes decreased $2 million, or 2.0%, in 2014 compared to 2013 primarily as a result of a $6 million decrease in franchise taxes, partially offset by a $3 million increase in ad valorem taxes and a $1 million increase 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 $365 million and $868 million were recorded in 2015 and 2014, 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 decreased $26 million, or 19.1%, in 2015 as compared to 2014. The decrease in 2015 was primarily due to a reduction in the AFUDC rate driven by an increase in short-term borrowings and placing the combined cycle and the associated common facilities portion of the Kemper IGCC in service in August 2014. AFUDC equity increased $14 million, or 12.2%, in

2014 as compared to 2013. The increase in 2014 was 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 Construction" herein 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 decreased $38 million, or 84.4%, in 2015 compared to 2014. The decrease was primarily due to a $58 million decrease related to the termination of an agreement for SMEPA to purchase a portion of the Kemper IGCC which required the return of SMEPA's deposits at a lower rate of interest than accrued, a $5 million decrease associated with amended tax returns, and a $2 million decrease associated with the redemption of long-term debt in 2015. These decreases were partially offset by increases in interest expense of $10 million associated with additional issuances of debt in 2015, $9 million associated with unrecognized tax benefits, and $5 million related to the Mirror CWIP refund, partially offset by a $3 million decrease in AFUDC debt. See Note 5 to the financial statements for additional information.

Interest expense, net of amounts capitalized increased $9 million, or 24.2%, in 2014 compared to 2013, primarily due to an $11 million increase in interest expense resulting from the receipt of $125 million interest-bearing refundable deposits from SMEPA, an $8 million increase in interest expense on the regulatory liability related to the Kemper IGCC rate recovery, a $5 million increase in interest expense primarily associated with the issuances of long-term debt in 2014, and a $3 million increase in other interest expense. These increases in 2014 over the prior year were partially offset by a $15 million increase in capitalized interest resulting from carrying costs associated with the Kemper IGCC and a $3 million decrease in interest expense primarily associated with the redemption of long-term debt in late 2013.

See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle – Termination of Proposed Sale of Undivided Interest to SMEPA" for more information.

Other Income (Expense), Net

Other income (expense), net increased $6 million, or 42.9%, in 2015 compared to 2014 primarily due to $7 million associated with a settlement with the Sierra Club in 2014, partially offset by a $1 million increase in donations. Other income (expense), net decreased $7 million, or 133.7%, in 2014 compared to 2013 primarily due to $7 million associated with a settlement with the Sierra Club and a $1 million increase in consulting fees.

Income Taxes (Benefit)

Income taxes (benefit) increased $213 million, or 74.7%, in 2015 compared to 2014 and increased $83 million, or 22.5%, in 2014 compared to 2013 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 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 in accordance with any operational parameters that may be adopted by the Mississippi

PSC, as well as other ongoing construction projects. 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, developing new and maintaining existing energy contracts and associated load requirements with other utilities and other wholesale customers, energy conservation practiced by customers, the use of alternative energy sources by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in the Company's service territory. Demand for electricity is partially driven by economic growth. The pace of economic growth and electricity demand may be affected by changes in regional and global economic conditions, which may impact future earnings.

Environmental Matters

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

Environmental Statutes and Regulations

General

The 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; the Migratory Bird Treaty Act; the Bald and Golden Eagle Protection Act; and related federal and state regulations. Compliance with these environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. Through 2015, the Company had invested approximately $617 million in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $94 million, $118 million, and $104 million for 2015, 2014, and 2013, respectively. The Company expects that capital expenditures to comply with environmental statutes and regulations will total approximately $66 million from 2016 through 2018, with annual totals of approximately $21 million, $19 million, and $26 million for 2016, 2017, and 2018, respectively. These estimated expenditures do not include any potential capital expenditures that may arise from the EPA's final rules and guidelines or subsequently approved state plans that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. See "Global Climate Issues" herein for additional information. The Company also anticipates costs associated with closure in place and ground water monitoring of ash ponds in accordance with the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule), which are not reflected in the capital expenditures above, as these costs are associated with the Company's asset retirement obligation (ARO) liabilities. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein for additional information.

The 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, including the environmental regulations described below; the outcome of any legal challenges to the environmental rules; the cost, availability, and existing inventory of emissions allowances; and the 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 "Retail Regulatory Matters – Environmental Compliance Overview Plan" herein for additional information.

Compliance with any new federal or state legislation or regulations relating to air, water, and land resources or other environmental and health concerns could significantly affect the Company. Although new or revised environmental legislation or regulations could affect many areas of the 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. Additional controls are currently planned or under consideration to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements.

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

The EPA regulates ground level ozone concentrations through implementation of an eight-hour ozone National Ambient Air Quality Standard (NAAQS). On October 26, 2015, the EPA published a more stringent eight-hour ozone NAAQS. This new standard could potentially require additional emission controls, improvements in control efficiency, and operational fuel changes and could affect the siting of new generating facilities. States will recommend area designations by October 2016, and the EPA is expected to finalize them by October 2017.

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 finalized a data requirements rule to support additional designation decisions for SO_2 in the future, which could result in nonattainment designations for areas within the 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.

In February 2014, the EPA proposed to delete from the Alabama State Implementation Plan (SIP) the Alabama opacity rule that the EPA approved in 2008, which provides operational flexibility to affected units, including units co-owned by the Company. In 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 having begun in 2015 and Phase II beginning in 2017. On July 28, 2015, the U.S. Court of Appeals for the District of Columbia Circuit issued an opinion invalidating certain emissions budgets under the CSAPR Phase II emissions trading program for a number of states, including Alabama, but rejected all other pending challenges to the rule. The court's decision leaves the emissions trading program in place and remands the rule to the EPA for further action consistent with the court's decision. On December 3, 2015, the EPA published a proposed revision to CSAPR that would revise existing ozone-season emissions budgets for nitrogen oxide in Alabama and Mississippi. The EPA proposes to finalize this rulemaking by summer 2016.

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

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

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

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, regional haze regulations, 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 capital expenditures and compliance costs that could affect future unit retirement and replacement decisions and results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

See Note 3 to the financial statements under "Retail Regulatory Matters – Environmental Compliance Overview Plan" 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 in October 2014. The effect of this final rule will depend on the results of additional studies and implementation of the rule by regulators based on site-specific factors. National Pollutant Discharge Elimination System permits issued after July 14, 2018 must include conditions to implement and ensure compliance with the standards and protective measures required by the rule. The ultimate impact of this rule will also depend on the outcome of ongoing legal challenges and cannot be determined at this time.

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

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

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

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

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

Environmental Remediation

The Company must comply with other environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company could incur substantial costs to clean up affected sites. 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

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

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

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

The EPA's greenhouse gas reporting rule requires annual reporting of CO_2 equivalent emissions in metric tons for a company's operational control of facilities. Based on ownership or financial control of facilities, the Company's 2014 greenhouse gas emissions were approximately 11 million metric tons of CO_2 equivalent. The preliminary estimate of the Company's 2015 greenhouse gas emissions on the same basis is approximately 9 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

Municipal and Rural Associations Tariff

In 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.

In March 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 in May 2014, provided that base rates under the MRA cost-based electric tariff increased approximately $10 million annually, effective May 1, 2014.

Included in this settlement agreement, an adjustment to the Company's wholesale revenue requirement in a subsequent rate proceeding was allowed in the event the Kemper IGCC, or any substantial portion thereof, was placed in service before or after December 1, 2014. Therefore, the Company recorded a regulatory asset as a result of a portion of the Kemper IGCC being placed in service prior to the projected date, which was fully amortized as of December 31, 2015.

On May 13, 2015, the FERC accepted a further settlement agreement between the Company and its wholesale customers to forgo a MRA cost-based electric tariff increase by, among other things, increasing the accrual of AFUDC and lowering the portion of CWIP in rate base, effective April 1, 2015. The additional resulting AFUDC is estimated to be approximately $14 million annually, of which $11 million relates to the Kemper IGCC.

See Note 3 to the financial statements under "FERC Matters" for more information.

Fuel Cost Recovery

The Company has a wholesale MRA and a Market Based (MB) fuel cost recovery factor. Effective January 1, 2016, the wholesale MRA fuel rate decreased $47 million annually. Effective February 1, 2016, the wholesale MB fuel rate decreased $2 million annually. At December 31, 2015, the amount of over-recovered wholesale MRA fuel costs included in the balance sheets was $24 million compared to an immaterial balance at December 31, 2014.

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.

See Note 3 to the financial statements under "FERC Matters" for more information.

Market-Based Rate Authority

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

Retail Regulatory Matters

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 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.

Renewables

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

Energy Efficiency

In 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.

In June 2014, the Mississippi PSC approved the Company's 2014 Energy Efficiency Quick Start Plan filing, which includes a portfolio of energy efficiency programs. In November 2014, the Mississippi PSC approved the Company's revised compliance filing, which proposed an increase of $7 million in retail revenues for the period December 2014 through December 2015. On December 4, 2015, the Company submitted its annual Energy Efficiency Cost Rider Compliance filing, which included a reduction of $2 million in retail revenues for the year ending December 31, 2016. The ultimate outcome of this matter cannot be determined at this time.

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 2013, the MPUS contested the Company's PEP lookback filing for 2012, which indicated a refund due to customers of $5 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 2013, the Mississippi PSC approved the projected PEP filing for 2013, which resulted in a rate increase of 1.9%, or $15 million, annually, effective March 19, 2013. The Company may be entitled to $3 million in additional revenues related to 2013 as a result of the late implementation of the 2013 PEP rate increase.

In March 2014 and 2015, the Company submitted its annual PEP lookback filings for 2013 and 2014, respectively, which each indicated no surcharge or refund. The Mississippi PSC suspended each of the filings to allow more time for review.

In June 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 were placed in service in November 2015. These units are jointly owned by the Company and Gulf Power, with 50% ownership each. In August 2014, the Company entered into a settlement agreement with the Sierra Club that, among other things, required 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, which also occurred in August 2014. 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 (which occurred on April 16, 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.

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, 2015, $5 million of Plant Greene County costs and $36 million of costs related to Plant Watson have been reclassified as regulatory assets. 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 2016. 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.

On December 3, 2015, the Mississippi PSC approved the Company's revised ECO filing for 2015, which indicated no change in revenue.

On February 12, 2016, the Company submitted its ECO filing for 2016, which requested an increase in annual revenues, capped at 2% of total retail revenues, of approximately $18 million, primarily related to the scrubbers on Plant Daniel Units 1 and 2. The revenue requirement in excess of the 2%, approximately $26 million, will be carried forward to the 2017 filing. The ultimate outcome of this matter 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 Mississippi PSC approved the 2016 retail fuel cost recovery factor, effective January 21, 2016, which will result in an annual revenue decrease of approximately $120 million. At December 31, 2015, the amount of over-recovered retail fuel costs included in the balance sheets was $71 million compared to a $3 million under-recovered balance at December 31, 2014.

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.

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 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 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 using natural gas in August 2014 and currently expects to place the remainder of the Kemper IGCC, including the gasifier and the gas clean-up facilities, in service during the third quarter 2016.

Recovery of the costs subject to the cost cap and the Cost Cap Exceptions remains 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, 2015, are as follows:

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

(a) Amounts in the Current Cost Estimate reflect estimated costs through August 31, 2016.

(b) The 2012 MPSC CPCN Order approved a construction cost cap of up to $2.88 billion, net of the DOE Grants and excluding the Cost Cap Exceptions. The Current Cost Estimate and the Actual Costs include non-incremental operating and maintenance costs related to the combined cycle and associated common facilities placed in service in August 2014 that are subject to the $2.88 billion cost cap and exclude post-in-service costs for the lignite mine. See "Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order" herein for additional information. The Current Cost Estimate and the Actual Costs reflect 100% of the costs of the Kemper IGCC. See note (g) for additional information.

(c) 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." The current estimate reflects the impact of a settlement agreement with the wholesale customers for cost-based rates under FERC's jurisdiction. See "FERC Matters" herein for additional information.

(d) Incremental operating and maintenance costs related to the combined cycle and associated common facilities placed in service in August 2014, net of costs related to energy sales. See "Rate Recovery of Kemper IGCC Costs — 2013 MPSC Rate Order" herein for additional information.

(e) The 2012 MPSC CPCN Order approved deferral of non-capital Kemper IGCC-related costs during construction as described in "Rate Recovery of Kemper IGCC Costs – Regulatory Assets and Liabilities" herein.

(f) The 2010 Project Estimate is the certificated cost estimate adjusted to include the certificated estimate for the CO_2 pipeline facilities which was approved in 2011 by the Mississippi PSC.

(g) Beginning in the third quarter 2015, certain costs, including debt carrying costs (associated with assets placed in service and other non-CWIP accounts), that previously were deferred as regulatory assets are now being recognized through income; however, such costs continue to be included in the Current Cost Estimate and the Actual Costs at December 31, 2015.

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

The Company does not intend to seek rate recovery for any costs related to the construction of the Kemper IGCC that exceed the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions. The Company recorded pre-tax charges to income for revisions to the cost estimate above the cost cap of $365 million ($226 million after tax), $868 million ($536 million after tax), and $1.1 billion ($681 million after tax) in 2015, 2014, and 2013, respectively. The increases to the cost estimate in 2015 primarily reflect costs for the extension of the Kemper IGCC's projected in-service date through August 31, 2016, increased efforts related to scope modifications, additional labor costs in support of start-up and operational readiness activities, and system repairs and modifications after startup testing and commissioning activities identified necessary remediation of equipment installation, fabrication, and design issues, including the refractory lining inside the gasifiers; the lignite feed and dryer systems; and the syngas cooler vessels. Any extension of the in-service date beyond August 31, 2016 is currently estimated to result in additional base costs of approximately $25 million to $35 million per month, which includes maintaining necessary levels of start-up labor, materials, and fuel, as well as operational resources required to execute start-up and commissioning activities. However, additional costs may be required for remediation of any further equipment and/or design issues identified. Any extension of the in-service date with respect to the Kemper IGCC beyond August 31, 2016 would also increase costs for the Cost Cap Exceptions, which are not subject to the $2.88 billion cost cap established by the Mississippi PSC. These costs include AFUDC, which is currently estimated to total approximately $13 million per month, as well as carrying costs and operating expenses on Kemper IGCC assets placed in service and consulting and legal fees of approximately $2 million per month. For additional information, see "2015 Rate Case" herein.

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

Rate Recovery of Kemper IGCC Costs

See "FERC Matters" herein 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 "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 future proceedings related to the operation of the Kemper IGCC. To the extent the Mississippi PSC determines the Kemper IGCC does not meet the operational parameters ultimately adopted by the Mississippi PSC or the Company incurs additional costs to satisfy such parameters, there could be a material adverse impact on the Company's financial statements.

2013 MPSC Rate Order

In January 2013, the Company entered into a settlement agreement with the Mississippi PSC that was intended to establish the process for resolving matters regarding cost recovery related to the Kemper IGCC (2013 Settlement Agreement). Under the 2013 Settlement Agreement, 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. In March 2013, the Mississippi PSC issued a rate order approving retail rate increases of 15% effective March 19, 2013 and 3% effective January 1, 2014, which collectively were designed to collect $156 million annually beginning in 2014 (2013 MPSC Rate Order) to be used to mitigate customer rate impacts after the Kemper IGCC is placed in service.

Because the 2013 MPSC Rate Order did not provide for the inclusion of CWIP in rate base as permitted by the Baseload Act, the Company continues to record AFUDC on the Kemper IGCC. 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.

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

2015 Rate Case

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

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

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

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

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

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

The Company expects to seek additional rate relief to address recovery of the remaining Kemper IGCC assets. In addition to current estimated costs at December 31, 2015 of $6.63 billion, 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.

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

Regulatory Assets and Liabilities

Consistent with the treatment of non-capital costs incurred during the pre-construction period, the Mississippi PSC issued an accounting order in 2011 granting 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.

In August 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. Beginning in the third quarter 2015, in connection with the implementation of interim rates, the Company began expensing certain ongoing project costs and certain debt carrying costs (associated with assets placed in service and other non-CWIP accounts) that previously were deferred as regulatory assets and began amortizing certain regulatory assets associated with assets placed in service and consulting and legal fees. The amortization periods for these regulatory assets vary from two years to 10 years as set forth in the In-Service Asset Rate Order. As of December 31, 2015, the balance associated with these regulatory assets was $120 million. Other regulatory assets associated with the remainder of the Kemper IGCC totaled $96 million as of December 31, 2015. The amortization period for these assets is expected to be determined by the Mississippi PSC in future rate proceedings following completion of construction and start-up of the Kemper IGCC and related prudence reviews.

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

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

Lignite Mine and CO_2 Pipeline Facilities

In conjunction with the Kemper IGCC, 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 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 Denbury and Treetop with termination rights as the Company has not satisfied its contractual obligation to deliver captured CO_2 by May 11, 2015. Since May 11, 2015, the Company has been engaged in ongoing discussions with its off-takers regarding the status of the CO_2 delivery schedule as well as other issues related to the CO_2 agreements. As a result of discussions with Treetop, on August 3, 2015, the Company agreed to amend certain provisions of their agreement that do not affect pricing or minimum purchase quantities. Potential requirements imposed on CO_2 off-takers under the Clean Power Plan (if ultimately enacted in its current form, pending resolution of litigation) and the potential adverse financial impact of low oil prices on the off-takers increase the risk that the CO_2 contracts may be terminated or materially modified. Any termination or material modification of these agreements could result in a material reduction in the Company's revenues to the extent the Company is not able to enter into other similar contractual arrangements. Additionally, if the contracts remain in place, sustained oil price reductions could result in significantly lower revenues than the Company forecasted to be available to offset customer rate impacts, which could have a material impact on the Company's financial statements. See "Environmental Matters – Global Climate Issues" herein for additional information regarding the Clean Power Plan and related litigation.

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

Termination of Proposed Sale of Undivided Interest to SMEPA

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

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

Income Tax Matters

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

Bonus Depreciation

On December 18, 2015, the Protecting Americans from Tax Hikes (PATH) Act was signed into law. Bonus depreciation was extended for qualified property placed in service over the next five years. The PATH Act allows for 50% bonus depreciation for 2015, 2016, and 2017; 40% bonus depreciation for 2018; and 30% bonus depreciation for 2019 and certain long-lived assets placed in service in 2020. The extension of 50% bonus depreciation is expected to result in approximately $85 million of positive cash flows for the 2015 tax year and approximately $390 million for the 2016 tax year, which may not all be realized in 2016 due to a projected net operating loss in the Company's 2016 tax return. Approximately $360 million of the 2016 benefit is dependent upon placing the remainder of the Kemper IGCC in service in 2016. The ultimate outcome of this matter cannot be determined at this time.

Investment Tax Credits

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

Section 174 Research and Experimental Deduction

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

Other Matters

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.

On April 16, 2015, the majority of assets that supported coal generation at Plant Watson Units 4 and 5 were retired. The remaining net book value of these two units was approximately $32 million, excluding the reserve for cost of removal, and has been reclassified to other regulatory assets, deferred, in accordance with an accounting order from the Mississippi PSC. The Company expects to recover through its rates the remaining book value of the retired assets and certain costs, including unusable inventory, associated with the retirements; however, the ultimate method and timing of recovery will be considered by the Mississippi PSC in future rate proceedings.

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

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.

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

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

As a result of the revisions to the cost estimate, the Company recorded total pre-tax charges to income for the estimated probable losses on the Kemper IGCC of $183 million ($113 million after tax) in the fourth quarter 2015, $150 million ($93 million after tax) in the third quarter 2015, $23 million ($14 million after tax) in the second quarter 2015, $9 million ($6 million after tax) in the first quarter 2015, $70 million ($43 million after tax) in the fourth quarter 2014, $418 million ($258 million after tax) in the third quarter 2014, $380 million ($235 million after tax) in the first quarter 2014, $40 million ($25 million after tax) in the fourth quarter 2013, $150 million ($93 million after tax) in the third quarter 2013, $450 million ($278 million after tax) in the second quarter 2013, $462 million ($285 million after tax) in the first quarter 2013, and $78 million ($48 million after tax) in the fourth quarter 2012. In the aggregate, the Company has incurred charges of $2.4 billion ($1.5 billion after tax) as a result of changes in the cost estimate above the cost cap for the Kemper IGCC through December 31, 2015.

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 operating or other agreements, operational readiness, including specialized operator training and required site safety programs, unforeseen engineering or design problems, start-up activities for this first-of-a-kind technology (including major equipment failure and system integration), and/or operational performance (including, but not limited to, additional costs to satisfy any operational parameters ultimately adopted by the Mississippi PSC).

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

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

Asset Retirement Obligations

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

The liability for AROs primarily relates to facilities that are subject to the CCR Rule, principally ash ponds. In addition, the Company has retirement obligations 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 retirement obligations related to certain transmission and distribution facilities, and certain wireless communication towers. However, liabilities for the removal of these assets have not been recorded because the settlement timing for the retirement obligations related to these assets is indeterminable and, therefore, the fair value of the retirement obligations cannot be reasonably estimated. A liability for these AROs will be recognized when sufficient information becomes available to support a reasonable estimation of the ARO.

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

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

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

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 are the expected long-term return on plan assets and the discount rate used to measure the benefit plan obligations and the periodic benefit plan expense for future periods. The expected long-term return on pension and other postretirement benefit plan assets is based on 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. For purposes of determining its liability related to the pension and other postretirement benefit plans, the Company discounts the future related cash flows 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 2015 and prior years, the Company computed the interest cost component of its net periodic pension and other postretirement benefit plan expense using the same single-point discount rate. For 2016, the Company has adopted a full yield curve approach for calculating the interest cost component whereby the discount rate for each year is applied to the liability for that specific year. As a result, the interest cost component of net periodic pension and other postretirement benefit plan expense will decrease by approximately $4 million in 2016.

A 25 basis point change in any significant assumption (discount rate, salaries, or long-term return on plan assets) would result in a $1 million or less change in total annual benefit expense and a $20 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 5.99%, 6.91%, and 6.89% for the years ended December 31, 2015, 2014, and 2013, respectively. The AFUDC rate is applied to CWIP consistent with jurisdictional regulatory treatment. AFUDC equity was $110 million, $136 million, and $122 million, in 2015, 2014, and 2013, respectively.

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.

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 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 results of operations, cash flows, or financial condition.

Recently Issued Accounting Standards

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

On April 7, 2015, the FASB issued Accounting Standards Update (ASU) No. 2015-03, *Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs* (ASU 2015-03). ASU 2015-03 requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability and is effective for fiscal years beginning after December 15, 2015. As permitted, the Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. The new guidance resulted in an adjustment to the presentation of debt issuance costs as an offset to the related debt balances primarily in long-term debt totaling $9 million as of December 31, 2014. These debt issuance costs were previously presented within other deferred charges and assets. Other than the reclassification, the adoption of ASU 2015-03 did not have an impact on the results of operations, cash flows, or financial condition of the Company. See Note 9 to the financial statements for disclosures impacted by ASU 2015-03.

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

On November 20, 2015, the FASB issued ASU No. 2015-17, *Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes* (ASU 2015-17), which simplifies the presentation of deferred income taxes. ASU 2015-17 requires deferred tax assets and liabilities to be presented as non-current in a classified balance sheet and is effective for fiscal years beginning after December 15, 2016, including interim periods within that reporting period. As permitted, the Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. Prior to the adoption of ASU 2015-17, all deferred income tax assets and liabilities were required to be separated into current and non-current amounts. The new guidance resulted in a reclassification from prepaid income taxes of $121 million with $105 million to non-current accumulated deferred income taxes and $16 million to other deferred charges in the Company's December 31, 2014 balance sheet. Other than the reclassification, the adoption of ASU 2015-17 did not have an impact on the results of operations, cash flows, or financial condition of the Company. See Note 5 to the financial statements for disclosures impacted by ASU 2015-17.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition and its ability to obtain financing needed for normal business operations and completion of construction and start-up of the Kemper IGCC were adversely affected by the return of approximately $301 million of interest bearing refundable deposits to SMEPA in June 2015 in connection with the termination of the APA, the required refund of the approximately $371 million of Mirror CWIP rate collections, including associated carrying costs, the termination of the Mirror CWIP rate, and the required recapture of Phase II tax credits. Earnings for the twelve months ended December 31, 2015 were negatively affected by revisions to the cost estimate for the Kemper IGCC and the Court's decision to reverse the 2013 MPSC Rate Order. See FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle – Termination of Proposed Sale of Undivided Interest to SMEPA," –"Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order," "– 2015 Rate Case," and – "Income Tax Matters – Investment Tax Credits" herein for additional information.

Through December 31, 2015, the Company has incurred non-recoverable cash expenditures of $1.95 billion and is expected to incur approximately $0.46 billion in additional non-recoverable cash expenditures through completion of the construction and start-up of the Kemper IGCC.

In addition to funding normal business operations and projected capital expenditures, the Company's near-term cash requirements primarily consist of $900 million of bank term loans scheduled to mature on April 1, 2016, $300 million in senior notes scheduled to mature on October 15, 2016, $25 million of short-term debt, and the required refund of approximately $11 million in customer refunds associated with the In-Service Asset Rate Order. For the three-year period from 2016 through 2018, 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, to add environmental modifications to existing generating units, to add or change fuel sources for certain existing units, and to expand and improve transmission and distribution facilities. The Company expects to refinance its 2016 debt maturities with bank term loans. The Company intends to utilize operating cash flows and lines of credit (to the extent available) as well as loans and, under certain circumstances, equity contributions from Southern Company to fund the remainder of the Company's capital needs. See "Capital Requirements and Contractual Obligations," "Sources of Capital," and "Financing Activities herein for additional information.

The Company's investments in the qualified pension plan remained stable in value as of December 31, 2015 as compared to December 31, 2014. No contributions to the qualified pension plan were made for the year ended December 31, 2015, and no mandatory contributions to the qualified pension plan are anticipated during 2016.

Net cash provided from operating activities totaled $173 million for 2015, a decrease of $562 million as compared to 2014. The decrease in net cash provided from operating activities was primarily due to lower R&E tax deductions and lower incremental benefit of ITCs relating to the Kemper IGCC reducing income tax refunds, as well as a decrease in the Mirror CWIP regulatory liability due to the Mirror CWIP refund, partially offset by increases in over recovered regulatory clause revenues and customer liability associated with the Mirror CWIP refund. Net cash provided from operating activities totaled $735 million for 2014, an increase of $287 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 rate collections, 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 used for investing activities in 2015, 2014, and 2013 totaled $0.9 billion, $1.3 billion, and $1.6 billion, respectively. The cash used for investing activities in each of these years was primarily due to gross property additions related to the Kemper IGCC and the Plant Daniel scrubber project.

Net cash provided from financing activities totaled $698 million in 2015 primarily due to short-term borrowings, capital contributions from Southern Company, and long-term debt financings, partially offset by redemptions of long-term debt. Net cash provided from financing activities totaled $593 million in 2014 primarily due to capital contributions from Southern Company, long-term debt financings, and the receipts of interest bearing refundable deposits previously pending, 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, 2015 compared to 2014 included an increase in notes payable of $500 million. Income taxes receivable non-current increased $544 million due to unrecognized tax benefits associated with R&E expenditures for the 2008 through 2013 amended tax returns. Total property, plant, and equipment increased $512 million and Mirror CWIP decreased $271 million primarily associated with the construction and collections for the Kemper IGCC. See FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle" herein for additional information. Accumulated deferred income taxes increased $582 million primarily due to R&E tax deductions and accumulated deferred investment tax credits decreased $278 million, due to the recapture of Phase II tax credits. See FUTURE EARNINGS POTENTIAL – "Income Tax Matters – Investment Tax Credits" herein for additional information. Total common stockholder's equity increased $275 million due to the receipt of capital contributions from Southern Company. Other regulatory assets, deferred, increased $140 million primarily due to the Kemper IGCC. See FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle" herein for additional information.

The Company's ratio of common equity to total capitalization, including long-term debt due within one year, was 47.1% in 2015 and 46.1% in 2014. See Note 6 to the financial statements for additional information.

Sources of Capital

As discussed above, the Company's financial condition and its ability to obtain funds needed for normal business operations and completion of the construction and start-up of the Kemper IGCC were adversely affected in 2015 by events relating to the Kemper IGCC. On December 3, 2015, the Mississippi PSC approved the In-Service Asset Rate Order which, among other things, provides for retail rate recovery of an annual revenue requirement of approximately $126 million which became effective on December 17, 2015. See FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs – 2015 Rate Case," herein for additional information. The amount, type, and timing of future financings will depend upon regulatory approval, prevailing market conditions, and other factors, which includes resolution of Kemper IGCC cost recovery. See "Capital Requirements and Contractual Obligations" herein and FUTURE EARNINGS POTENTIAL –

"Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order," and " – 2015 Rate Case" herein for additional information.

In April 2015, the Company entered into two floating rate bank loans with a maturity date of April 1, 2016, in an aggregate principal amount of $475 million, bearing interest based on one-month LIBOR. The proceeds of these loans were used for the repayment of term loans in an aggregate principal amount of $275 million, working capital, and other general corporate purposes. The Company also amended three outstanding floating rate bank loans for an aggregate principal amount of $425 million which, among other things, extended the maturity dates from various dates in 2015 to April 1, 2016. In addition, the Company received $275 million in equity contributions from Southern Company and issued two promissory notes for up to $676 million to Southern Company bearing interest based on one-month LIBOR. As of December 31, 2015, an aggregate of $576 million was outstanding under these promissory notes, all maturing in December 2017. On January 28, 2016, the Company issued a further promissory note for up to $275 million to Southern Company, which matures in December 2017, bearing interest based on one-month LIBOR. During January 2016, the Company borrowed $150 million pursuant to the existing promissory notes.

As of December 31, 2015, the Company's current liabilities exceeded current assets by approximately $1.3 billion primarily due to $900 million of bank term loans scheduled to mature on April 1, 2016 and $300 million in senior notes scheduled to mature on October 15, 2016. The Company expects to refinance its 2016 debt maturities with bank term loans. The Company intends to utilize operating cash flows and lines of credit (to the extent available) as well as loans and, under certain circumstances, equity contributions from Southern Company to fund the remainder of the Company's capital needs.

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

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

The issuance of securities by the Company is subject to regulatory approval by the FERC. Additionally, public offerings of securities are required to be registered with the SEC under the Securities Act of 1933, as amended. The amounts of securities authorized by the FERC 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.

At December 31, 2015, the Company had approximately $98 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2015 were as follows:

Expires			Executable Term-Loans		Due Within One Year	
2016	Total	Unused	One Year	Two Years	Term Out	No Term Out
(in millions)	(in millions)		(in millions)		(in millions)	
$ 220	$ 220	$ 195	$ 30	$ 15	$ 45	$ 175

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 typically contain cross acceleration or 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 specific threshold. Such cross acceleration provisions to other indebtedness would trigger an event of default if the Company defaulted on indebtedness, the payment of which was then accelerated. 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.

Subject to applicable market conditions, the Company expects to renew or replace its bank credit arrangements, as needed prior to expiration. In connection therewith, the Company may extend the maturity dates and/or increase or decrease the lending commitments thereunder.

A portion of the $195 million unused credit arrangements with banks is allocated to provide liquidity support to the Company's 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, 2015 was $40 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. The Company has not issued any commercial paper through this program since 2013 and does not intend to make any issuances during 2016.

The Company had no short-term borrowings in 2014. Details of short-term borrowing for 2013 and 2015 were as follows:

	Short-term Debt at the End of the Period		Short-term Debt During the Period (*)		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
December 31, 2015	$500	1.4%	$372	1.3%	$515
December 31, 2013	$—	—%	$23	0.2%	$148

(*) 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 March 2015, the Company repaid at maturity a $75 million bank term loan.

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

These bank loans have covenants that limit debt levels to 65% of total capitalization, as defined in the agreements. For purposes of these definitions, debt excludes the long-term debt payable to affiliated trusts, other hybrid securities, and securitized debt relating to the securitization of certain costs of the Kemper IGCC. At December 31, 2015, the Company was in compliance with its debt limits.

In addition, these bank loans 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 Obligations

In June 2015, the Company issued an additional floating rate promissory note to Southern Company. This note was for an aggregate principal amount of approximately $301 million, the amount paid by Southern Company to SMEPA pursuant to Southern Company's guarantee of the return of SMEPA's deposits in connection with the termination of the APA. In December 2015, the $301 million promissory note was amended which, among other things, changed the maturity date to December 1, 2017. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle – Termination of Proposed Sale of Undivided Interest to SMEPA" for additional information.

In November 2015, the Company issued an additional floating rate promissory note to Southern Company in an aggregate principal amount of up to $375 million, which matures on December 1, 2017. As of December 31, 2015, the Company had borrowed $275 million under the promissory note. On January 19, 2016, the Company borrowed the remaining $100 million. Also, subsequent to December 31, 2015, the Company issued an additional floating rate promissory note to Southern Company in an aggregate principal amount of up to $275 million, which matures on December 1, 2017. The Company has borrowed $50 million under the promissory note.

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 have required or could require collateral, but not accelerated payment, in the event of a credit rating change to BBB and/or Baa2 or below. These contracts are for physical electricity sales, fuel transportation and storage, energy price risk management, and transmission. At December 31, 2015, the maximum amount of potential collateral requirements under these contracts at a rating of BBB and/or Baa2 or BBB- and/or Baa3 was not material. The maximum potential collateral requirements at a rating below BBB- and/or Baa3 equaled approximately $267 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, a credit rating downgrade could impact the ability of the Company to access capital markets, and would be likely to impact the cost at which it does so.

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

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

On August 17, 2015, S&P downgraded the issuer rating of the Company to BBB+ from A. S&P revised its credit rating outlook from negative to stable. Separately, on August 24, 2015, S&P revised its consolidated credit rating outlook of Southern Company (including the Company) from stable to negative following the announcement of the proposed merger of a wholly-owned direct subsidiary of Southern Company with and into AGL Resources Inc.

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

Market Price Risk

Due to cost-based rate regulation and other various cost recovery mechanisms, the Company continues to have limited exposure to market volatility in interest rates, 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 $1 billion of long-term variable interest rate exposure at December 31, 2015 was 1.66%. 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 $10 million at January 1, 2016. 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, 2015 when compared to the year ended December 31, 2014.

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

	2015 Changes	2014 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$ (45)**	$ (5)
Contracts realized or settled	**33**	(3)
Current period changes(*)	**(35)**	(37)
Contracts outstanding at the end of the period, assets (liabilities), net	**$ (47)**	$ (45)

(*) 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, all of which are natural gas swaps, for the years ended December 31 were as follows:

	2015	2014
	mmBtu Volume	
	(in millions)	
Total hedge volume	**32**	54

For natural gas hedges, the weighted average swap contract cost above market prices was approximately $1.49 per mmBtu as of December 31, 2015 and $0.84 per mmBtu as of December 31, 2014. 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, 2015 and 2014, 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.

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, 2015 were as follows:

	Fair Value Measurements December 31, 2015		
	Total	Maturity	
	Fair Value	Year 1	Years 2&3
	(in millions)		
Level 1	$ —	$ —	$ —
Level 2	(47)	(29)	(18)
Level 3	—	—	—
Fair value of contracts outstanding at end of period	$ (47)	$ (29)	$ (18)

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

Approximately $900 million will be required through December 31, 2016 to fund maturities of bank term loans scheduled to mature on April 1, 2016, $300 million in senior notes scheduled to mature on October 15, 2016, and $25 million in short-term debt. See "Sources of Capital" herein for additional information.

The construction program of the Company is currently estimated to total $787 million for 2016, $216 million for 2017, and $264 million for 2018, which includes expenditures related to the construction of the Kemper IGCC of $612 million in 2016. These estimated amounts also include capital expenditures covered under long-term service agreements. Estimated capital expenditures to comply with environmental statutes and regulations included in these amounts are $21 million, $19 million, and $26 million for 2016, 2017, and 2018, respectively. These estimated expenditures do not include any potential compliance costs that may arise from the EPA's final rules and guidelines or subsequently approved state plans that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" and "– Global Climate Issues" and – "Integrated Coal Gasification Combined Cycle" herein for additional information.

The Company also anticipates costs associated with closure in place and ground water monitoring of ash ponds in accordance with the CCR Rule, which are not reflected in the capital expenditures above as these costs are associated with the Company's ARO liabilities. These costs, which could change as the Company continues to refine its assumptions underlying the cost estimates and evaluate the method and timing of compliance, are estimated to be $39 million, $12 million, and $11 million for the years 2016, 2017, and 2018, respectively. See Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" for additional information.

The construction 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, unrecognized tax benefits, pension and other post-retirement benefit plans, 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.

Contractual Obligations

	2016	2017-2018	2019-2020	After 2020	Total
			(in millions)		
Long-term debt[a] —					
Principal	$ 725	$ 611	$ 132	$ 1,026	$ 2,494
Interest	87	132	114	670	1,003
Preferred stock dividends[b]	2	3	3	—	8
Financial derivative obligations[c]	29	18	—	—	47
Unrecognized tax benefits[d]	—	421	—	—	421
Operating leases [e]	2	2	1	—	5
Capital leases[f]	3	6	7	61	77
Purchase commitments —					
Capital[g]	752	453	—	—	1,205
Fuel[h]	142	229	191	254	816
Long-term service agreements[i]	34	65	50	215	364
Pension and other postretirement benefits plans[j]	7	14	—	—	21
Total	$ 1,783	$ 1,954	$ 498	$ 2,226	$ 6,461

(a) All amounts are reflected based on final maturity dates. The Company plans to continue, when economically feasible, to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of January 1, 2016, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk. Long-term debt excludes capital lease amounts (shown separately).

(b) 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 associated with environmental regulations. At December 31, 2015, 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" herein 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, 2015.

(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.

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2015 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, pending or potential litigation matters, access to sources of capital, projections for the qualified pension plan and postretirement benefit plans contributions, financing activities, completion of construction projects and changing fuel sources, filings with state and federal regulatory authorities, impact of the PATH Act, 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 regulating emissions, discharges, and disposal to air, water, and land, 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, without limitation, 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 operating or other agreements, operational readiness, including specialized operator training and required site safety programs, unforeseen engineering or design problems, start-up activities (including major equipment failure and system integration), and/or operational performance (including additional costs to satisfy any operational parameters ultimately adopted by the Mississippi PSC);
- the ability to construct facilities in accordance with the requirements of permits and licenses, to satisfy any environmental performance standards and the requirements of tax credits and other incentives, and to integrate facilities into the Southern Company system upon completion of construction;
- investment performance of 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 the ultimate impact of the 2015 decision of the Mississippi Supreme Court, the Mississippi PSC's December 2015 rate order, and related legal or regulatory proceedings, Mississippi PSC review of the prudence of Kemper IGCC costs and approval of further permanent rate recovery plans, actions relating to proposed securitization, satisfaction of requirements to utilize grants, and the ultimate impact of the termination of the proposed sale of an interest in the Kemper IGCC to SMEPA;
- 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 (or sell excess generating capacity) at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes and other storms, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the 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, 2015, 2014, and 2013
Mississippi Power Company 2015 Annual Report

	2015	2014	2013
		(in millions)	
Operating Revenues:			
Retail revenues	**$ 776**	$ 795	$ 799
Wholesale revenues, non-affiliates	**270**	323	294
Wholesale revenues, affiliates	**76**	107	35
Other revenues	**16**	18	17
Total operating revenues	**1,138**	1,243	1,145
Operating Expenses:			
Fuel	**443**	574	491
Purchased power, non-affiliates	**5**	18	6
Purchased power, affiliates	**7**	25	43
Other operations and maintenance	**274**	271	253
Depreciation and amortization	**123**	97	91
Taxes other than income taxes	**94**	79	81
Estimated loss on Kemper IGCC	**365**	868	1,102
Total operating expenses	**1,311**	1,932	2,067
Operating Loss	**(173)**	(689)	(922)
Other Income and (Expense):			
Allowance for equity funds used during construction	**110**	136	122
Interest expense, net of amounts capitalized	**(7)**	(45)	(36)
Other income (expense), net	**(8)**	(14)	(7)
Total other income and (expense)	**95**	77	79
Loss Before Income Taxes	**(78)**	(612)	(843)
Income taxes (benefit)	**(72)**	(285)	(368)
Net Loss	**(6)**	(327)	(475)
Dividends on Preferred Stock	**2**	2	2
Net Loss After Dividends on Preferred Stock	**$ (8)**	$ (329)	$ (477)

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

STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2015, 2014, and 2013
Mississippi Power Company 2015 Annual Report

	2015	2014	2013
		(in millions)	
Net Loss	**$ (6)**	$ (327)	$ (475)
Other comprehensive income (loss):			
Qualifying hedges:			
Reclassification adjustment for amounts included in net income, net of tax of $1, $1, and $1, respectively	**1**	1	1
Total other comprehensive income (loss)	**1**	1	1
Comprehensive Loss	**$ (5)**	$ (326)	$ (474)

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

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2015, 2014, and 2013
Mississippi Power Company 2015 Annual Report

	2015	2014	2013
		(in millions)	
Operating Activities:			
Net loss	**$ (6)**	$ (327)	$ (475)
Adjustments to reconcile net loss to net cash provided from operating activities —			
Depreciation and amortization, total	**126**	104	92
Deferred income taxes	**777**	145	(396)
Investment tax credits	**(210)**	(38)	144
Allowance for equity funds used during construction	**(110)**	(136)	(122)
Pension, postretirement, and other employee benefits	**10**	(29)	14
Regulatory assets associated with Kemper IGCC	**(61)**	(72)	(35)
Estimated loss on Kemper IGCC	**365**	868	1,102
Income taxes receivable, non-current	**(544)**	—	—
Other, net	**(2)**	18	107
Changes in certain current assets and liabilities —			
-Receivables	**28**	(22)	(25)
-Fossil fuel stock	**(4)**	13	63
-Materials and supplies	**(13)**	(15)	(11)
-Prepaid income taxes	**(35)**	(50)	17
-Other current assets	**(1)**	(4)	(4)
-Other accounts payable	**(34)**	33	13
-Accrued interest	**(2)**	29	17
-Accrued taxes	**(11)**	39	11
-Over recovered regulatory clause revenues	**96**	(18)	(59)
-Mirror CWIP	**(271)**	180	—
-Customer liability associated with Kemper refunds	**73**	—	—
-Other current liabilities	**2**	17	(5)
Net cash provided from operating activities	**173**	735	448
Investing Activities:			
Property additions	**(857)**	(1,257)	(1,641)
Investment in restricted cash	**—**	(11)	—
Distribution of restricted cash	**—**	11	—
Cost of removal net of salvage	**(14)**	(13)	(10)
Construction payables	**(9)**	(50)	(50)
Proceeds from asset sales	**—**	—	79
Other investing activities	**(26)**	(20)	19
Net cash used for investing activities	**(906)**	(1,340)	(1,603)
Financing Activities:			
Proceeds —			
Capital contributions from parent company	**277**	451	1,077
Bonds — Other	**—**	23	42
Interest-bearing refundable deposit	**—**	125	—
Long-term debt issuance to parent company	**275**	220	—
Other long-term debt issuances	**—**	250	475
Short-term borrowings	**505**	—	—
Redemptions —			
Bonds — Other	**—**	(34)	(83)
Senior notes	**—**	—	(50)
Other long-term debt	**(350)**	(220)	(125)
Return of paid in capital	**—**	(220)	(105)
Payment of preferred stock dividends	**(2)**	(2)	(2)
Payment of common stock dividends	**—**	—	(72)
Other financing activities	**(7)**	—	(2)
Net cash provided from financing activities	**698**	593	1,155
Net Change in Cash and Cash Equivalents	**(35)**	(12)	—
Cash and Cash Equivalents at Beginning of Year	**133**	145	145
Cash and Cash Equivalents at End of Year	**$ 98**	$ 133	$ 145
Supplemental Cash Flow Information:			
Cash paid (received) during the period for —			
Interest (net of $66, $69, and $54 capitalized, respectively)	**$ 45**	$ 7	$ 20
Income taxes (net of refunds)	**(33)**	(379)	(134)
Noncash transactions —			
Accrued property additions at year-end	**105**	114	165
Capital lease obligation	**—**	—	83
Issuance of promissory note to parent related to repayment of interest-bearing refundable deposits and accrued interest	**301**	—	—

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

BALANCE SHEETS
At December 31, 2015 and 2014
Mississippi Power Company 2015 Annual Report

Assets	2015	2014
	(in millions)	
Current Assets:		
Cash and cash equivalents	$ 98	$ 133
Receivables —		
Customer accounts receivable	26	43
Unbilled revenues	36	35
Other accounts and notes receivable	10	11
Affiliated companies	20	51
Income taxes receivable, current	20	—
Fossil fuel stock, at average cost	104	100
Materials and supplies, at average cost	75	62
Other regulatory assets, current	95	73
Prepaid income taxes	39	70
Other current assets	8	5
Total current assets	531	583
Property, Plant, and Equipment:		
In service	4,886	4,378
Less accumulated provision for depreciation	1,262	1,173
Plant in service, net of depreciation	3,624	3,205
Construction work in progress	2,254	2,161
Total property, plant, and equipment	5,878	5,366
Other Property and Investments	11	5
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	290	226
Other regulatory assets, deferred	525	385
Income taxes receivable, non-current	544	—
Accumulated deferred income taxes	—	33
Other deferred charges and assets	61	44
Total deferred charges and other assets	1,420	688
Total Assets	$ 7,840	$ 6,642

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

BALANCE SHEETS
At December 31, 2015 and 2014
Mississippi Power Company 2015 Annual Report

Liabilities and Stockholder's Equity	**2015**	2014
	(in millions)	
Current Liabilities:		
Securities due within one year	**$ 728**	$ 778
Notes payable	**500**	—
Interest-bearing refundable deposits	**—**	275
Accounts payable —		
Affiliated	**85**	86
Other	**135**	178
Customer deposits	**16**	15
Accrued taxes —		
Accrued income taxes	**—**	142
Other accrued taxes	**85**	84
Accrued interest	**18**	76
Accrued compensation	**26**	26
Over recovered regulatory clause liabilities	**96**	1
Mirror CWIP	**—**	271
Customer liability associated with Kemper refunds	**73**	—
Other current liabilities	**74**	46
Total current liabilities	**1,836**	1,978
Long-Term Debt (See accompanying statements)	**1,886**	1,621
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**762**	180
Deferred credits related to income taxes	**8**	9
Accumulated deferred investment tax credits	**5**	283
Employee benefit obligations	**153**	148
Asset retirement obligations	**154**	48
Unrecognized tax benefits	**368**	2
Other cost of removal obligations	**165**	166
Other regulatory liabilities, deferred	**71**	64
Other deferred credits and liabilities	**40**	26
Total deferred credits and other liabilities	**1,726**	926
Total Liabilities	**5,448**	4,525
Cumulative Redeemable Preferred Stock (See accompanying statements)	**33**	33
Common Stockholder's Equity (See accompanying statements)	**2,359**	2,084
Total Liabilities and Stockholder's Equity	**$ 7,840**	$ 6,642
Commitments and Contingent Matters (See notes)		

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

STATEMENTS OF CAPITALIZATION
At December 31, 2015 and 2014
Mississippi Power Company 2015 Annual Report

	2015	2014	**2015**	2014
	(in millions)		*(percent of total)*	
Long-Term Debt:				
Long-term notes payable —				
2.35% due 2016	**$ 300**	$ 300		
5.60% due 2017	**35**	35		
5.55% due 2019	**125**	125		
1.63% to 5.40% due 2035-2042	**680**	680		
Adjustable rates (1.84% to 1.90% at 1/1/16) due 2016	**425**	775		
Total long-term notes payable	**1,565**	1,915		
Other long-term debt —				
Pollution control revenue bonds —				
5.15% due 2028	**43**	43		
Variable rate (0.16% at 1/1/16) due 2020	**7**	7		
Variable rates (0.10% to 0.11% at 1/1/16) due 2025-2028	**33**	33		
Plant Daniel revenue bonds (7.13%) due 2021	**270**	270		
Long-term debt payable to parent company (1.49% to 1.74%) due 2017	**576**	—		
Total other long-term debt	**929**	353		
Capitalized lease obligations	**77**	79		
Unamortized debt premium	**53**	63		
Unamortized debt discount	**(2)**	(2)		
Unamortized debt issuance expense	**(8)**	(9)		
Total long-term debt (annual interest requirement — $87 million)	**2,614**	2,399		
Less amount due within one year	**728**	778		
Long-term debt excluding amount due within one year	**1,886**	1,621	**44.1%**	43.3%
Cumulative Redeemable Preferred Stock:				
$100 par value —				
Authorized — 1,244,139 shares				
Outstanding — 334,210 shares				
4.40% to 5.25% (annual dividend requirement — $2 million)	**33**	33	**0.8**	0.9
Common Stockholder's Equity:				
Common stock, without par value —				
Authorized — 1,130,000 shares				
Outstanding — 1,121,000 shares	**38**	38		
Paid-in capital	**2,893**	2,612		
Accumulated deficit	**(566)**	(559)		
Accumulated other comprehensive loss	**(6)**	(7)		
Total common stockholder's equity	**2,359**	2,084	**55.1**	55.8
Total Capitalization	**$ 4,278**	$ 3,738	**100.0%**	100.0%

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

STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
For the Years Ended December 31, 2015, 2014, and 2013
Mississippi Power Company 2015 Annual Report

	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Total
				(in millions)		
Balance at December 31, 2012	1	$ 38	$ 1,401	$ 319	$ (9)	$ 1,749
Net loss after dividends on preferred stock	—	—	—	(477)	—	(477)
Capital contributions from parent company	—	—	976	—	—	976
Other comprehensive income (loss)	—	—	—	—	1	1
Cash dividends on common stock	—	—	—	(72)	—	(72)
Balance at December 31, 2013	1	38	2,377	(230)	(8)	2,177
Net loss after dividends on preferred stock	—	—	—	(329)	—	(329)
Capital contributions from parent company	—	—	235	—	—	235
Other comprehensive income (loss)	—	—	—	—	1	1
Balance at December 31, 2014	**1**	**38**	**2,612**	**(559)**	**(7)**	**2,084**
Net loss after dividends on preferred stock	**—**	**—**	**—**	**(8)**	**—**	**(8)**
Capital contributions from parent company	**—**	**—**	**281**	**—**	**—**	**281**
Other comprehensive income (loss)	**—**	**—**	**—**	**—**	**1**	**1**
Other	**—**	**—**	**—**	**1**	**—**	**1**
Balance at December 31, 2015	**1**	**$ 38**	**$ 2,893**	**$ (566)**	**$ (6)**	**$ 2,359**

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

Index to the Notes to Financial Statements

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Mississippi Power Company (the Company) is a wholly owned subsidiary of 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 provides 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 and for other electric services. 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. As such, the Company's financial statements reflect the effects of rate regulation in accordance with GAAP and comply with the accounting policies and practices prescribed by 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

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

On April 7, 2015, the FASB issued Accounting Standards Update (ASU) No. 2015-03, *Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs* (ASU 2015-03). ASU 2015-03 requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability and is effective for fiscal years beginning after December 15, 2015. As permitted, the Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. The new guidance resulted in an adjustment to the presentation of debt issuance costs as an offset to the related debt balances primarily in long-term debt totaling $9 million as of December 31, 2014. These debt issuance costs were previously presented within other deferred charges and assets. Other than the reclassification, the adoption of ASU 2015-03 did not have an impact on the results of operations, cash flows, or financial condition of the Company. See Note 9 for disclosures impacted by ASU 2015-03.

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

On November 20, 2015, the FASB issued ASU No. 2015-17, *Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes* (ASU 2015-17), which simplifies the presentation of deferred income taxes. ASU 2015-17 requires deferred tax assets and liabilities to be presented as non-current in a classified balance sheet and is effective for fiscal years beginning after December 15, 2016, including interim periods within that reporting period. As permitted, the Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. Prior to the adoption of ASU 2015-17, all deferred income tax assets and liabilities were required to be separated into current and non-current amounts. The new guidance resulted in a reclassification from prepaid income taxes of $121 million with $105 million to non-current accumulated deferred income taxes and $16 million to other deferred charges in the Company's December 31, 2014 balance sheet.

Other than the reclassification, the adoption of ASU 2015-17 did not have an impact on the results of operations, cash flows, or financial condition of the Company. See Note 5 for disclosures impacted by ASU 2015-17.

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 $295 million, $259 million, and $205 million during 2015, 2014, and 2013, 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 $11 million, $13 million, and $13 million in 2015, 2014, and 2013, respectively. Also, the Company reimburses Alabama Power for any direct fuel purchases delivered from an Alabama Power transfer facility, which were $8 million, $34 million, and $27 million in 2015, 2014, and 2013, 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 $27 million, $31 million, and $17 million in 2015, 2014, and 2013, 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 2015, 2014, or 2013.

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

Regulatory Assets and Liabilities

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

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

	2015	2014	Note
		(in millions)	
Retiree benefit plans – regulatory assets	**$ 163**	$ 169	(a,g)
Property damage	**(64)**	(62)	(i)
Deferred income tax charges	**291**	227	(c)
Remaining net book value of retired assets	**36**	2	(b)
Property tax	**27**	28	(d)
Vacation pay	**11**	11	(e,g)
Plant Daniel Units 3 and 4 regulatory assets	**29**	23	(j)
Other regulatory assets	**16**	18	(b)
Fuel-hedging (realized and unrealized) losses	**50**	47	(f,g)
Asset retirement obligations	**70**	11	(c)
Other cost of removal obligations	**(167)**	(166)	(c)
Kemper IGCC regulatory assets	**216**	148	(h)
Mirror CWIP	**—**	(271)	(h)
Other regulatory liabilities	**(11)**	(13)	(b)
Total regulatory assets (liabilities), net	**$ 667**	$ 172	

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 or 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 three years. Upon final settlement, actual costs incurred 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.

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

Government Grants

In 2010, the DOE, through a cooperative agreement with SCS, agreed to fund $270 million of the Kemper IGCC through the grants awarded to the project by the DOE under the Clean Coal Power Initiative Round 2 (DOE Grants). Through December 31, 2015, the Company has received grant funds of $245 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 21.0% of the Company's total operating revenues in 2015 and are largely subject to rolling 10-year cancellation notices. Historically, these wholesale customers have acted as a group and any changes in contractual relationships for one customer are likely to be followed by the other wholesale customers.

Except as described for the collection of the Company’s cost-based MRA electric tariff customers, 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.

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.

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

	2015	2014
	(in millions)	
Generation	**$ 2,723**	$ 2,293
Transmission	**688**	665
Distribution	**891**	854
General	**503**	485
Plant acquisition adjustment	**81**	81
Total plant in service	**$ 4,886**	$ 4,378

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. The portion of railway track maintenance costs not charged to operation and maintenance expenses are charged to fuel stock and recovered through the Company's fuel clause. Through second quarter 2015, all costs associated with the combined cycle and the associated common facilities portion of the Kemper IGCC, excluding the lignite mine, were deferred to a regulatory asset to be recovered over the life of the Kemper IGCC. Beginning in the third quarter 2015, the Company began expensing a portion of these ongoing cost previously deferred as regulatory assets. See Note 3 under "Integrated Coal Gasification Combined Cycle" for additional information.

Depreciation, Depletion, and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 4.7% in 2015, 3.3% in 2014, and 3.4% in 2013. The increase in the 2015 depreciation rate is primarily due to an asset retirement obligation (ARO) at Plant Watson incurred as a result of changes in environmental regulations. See "Asset Retirement Obligations and Other Costs of Removal" herein for additional information. Depreciation studies are conducted periodically to update the composite rates. On December 3, 2015, the Mississippi PSC approved the study filed in 2014, with new rates effective January 1, 2015. 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.

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. Through the second quarter 2015, depreciation associated with the combined cycle and the associated common facilities portion of the Kemper IGCC was deferred as a regulatory asset to be recovered over the life of the Kemper IGCC. Beginning in the third quarter 2015, the Company began expensing certain ongoing project costs, including depreciation, that previously were deferred as regulatory assets. See Note 3 under "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs" for additional information.

Asset Retirement Obligations and Other Costs of Removal

AROs are computed as the present value of the estimated ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. In the absence of quoted market prices, AROs are estimated using present value techniques in which estimates of future cash outlays associated with the asset retirements are discounted using a credit-adjusted risk-free rate. Estimates of the timing and amounts of future cash outlays are based on projections of when and how the assets will be retired and the cost of future removal activities. 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 liability for AROs primarily relates to facilities that are subject to the Disposal of Coal Combustion Residuals from Electric Utilities final rule published by the EPA on April 17, 2015 (CCR Rule), principally ash ponds. In addition, the Company has retirement obligations 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 and certain wireless communication towers. 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 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 AROs included in the balance sheets are as follows:

	2015	2014
	(in millions)	
Balance at beginning of year	**$ 48**	$ 42
Liabilities incurred	**101**	—
Liabilities settled	**(3)**	(3)
Accretion	**4**	2
Cash flow revisions	**27**	7
Balance at end of year	**$ 177**	$ 48

The increase in liabilities incurred and cash flow revisions in 2015 primarily relate to an increase in AROs associated with facilities impacted by the CCR Rule located at Plant Watson and Plant Greene County. The cost estimates for AROs related to the CCR Rule are based on information as of December 31, 2015 using various assumptions related to closure and post-closure costs, timing of future cash outlays, inflation and discount rates, and the potential methods for complying with the CCR Rule requirements for closure in place. As further analysis is performed, including evaluation of the expected method of compliance, refinement of assumptions underlying the cost estimates, such as the quantities of CCR at each site, and the determination of timing, including the potential for closing ash ponds prior to the end of their currently anticipated useful life, the Company expects to continue to periodically update these estimates.

The increase in cash flow revisions in 2014 related to the Company's AROs associated with the Plant Watson landfill and Plant Greene County asbestos.

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 5.99%, 6.91%, and 6.89% for the years ended December 31, 2015, 2014, and 2013, respectively. AFUDC equity was $110 million, $136 million, and $122 million in 2015, 2014, and 2013, 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 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 each of 2015, 2014, and 2013, the Company made retail accruals of $3 million. The Company accrued $0.3 million annually in 2015, 2014, and 2013 for the wholesale jurisdiction. As of December 31, 2015, the property damage reserve balances were $63 million and $1 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 on the balance sheets (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. Cash flows from derivatives are classified on the statement of cash flows in the same category as the hedged item. 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, 2015.

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.

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, 2015, the VIE consolidation resulted in an ARO asset and associated liability in the amounts of $21 million and $25 million, respectively. For the year ended December 31, 2014, the VIE consolidation resulted in an ARO and an associated liability in the amounts of $21 million and $24 million, respectively. For the year ended December 31, 2013, the VIE consolidation resulted in an ARO and associated liability in the amounts of $21 million and $23 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). No contributions to the qualified pension plan were made for the year ended December 31, 2015, and no mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2016. 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, 2016, no other postretirement trust contributions are expected.

Actuarial Assumptions

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

Assumptions used to determine net periodic costs:	2015	2014	2013
Pension plans			
Discount rate – interest costs	**4.17%**	5.01%	4.26%
Discount rate – service costs	**4.49**	5.01	4.26
Expected long-term return on plan assets	**8.20**	8.20	8.20
Annual salary increase	**3.59**	3.59	3.59
Other postretirement benefit plans			
Discount rate – interest costs	**4.03%**	4.85%	4.04%
Discount rate – service costs	**4.38**	4.85	4.04
Expected long-term return on plan assets	**7.23**	7.30	7.04
Annual salary increase	**3.59**	3.59	3.59

Assumptions used to determine benefit obligations:	2015	2014
Pension plans		
Discount rate	**4.69%**	4.17%
Annual salary increase	**4.46**	3.59
Other postretirement benefit plans		
Discount rate	**4.47%**	4.03%
Annual salary increase	**4.46**	3.59

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

For purposes of its December 31, 2015 measurement date, the Company adopted new mortality tables for its pension and other postretirement benefit plans, which reflect decreased life expectancies in the U.S. The adoption of new mortality tables reduced the projected benefit obligations for the Company's pension and other postretirement benefit plans by approximately $9 million and $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, 2015 were as follows:

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

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

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

Pension Plans

The total accumulated benefit obligation for the pension plans was $447 million at December 31, 2015 and $462 million at December 31, 2014. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2015 and 2014 were as follows:

	2015	2014
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 513**	$ 409
Service cost	**13**	10
Interest cost	**21**	20
Benefits paid	**(22)**	(17)
Actuarial loss (gain)	**(25)**	91
Balance at end of year	**500**	513
Change in plan assets		
Fair value of plan assets at beginning of year	**446**	387
Actual return on plan assets	**4**	40
Employer contributions	**2**	36
Benefits paid	**(22)**	(17)
Fair value of plan assets at end of year	**430**	446
Accrued liability	**$ (70)**	$ (67)

At December 31, 2015, the projected benefit obligations for the qualified and non-qualified pension plans were $470 million and $30 million, respectively. All pension plan assets are related to the qualified pension plan.

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

	2015	2014
	(in millions)	
Other regulatory assets, deferred	**$ 144**	$ 151
Other current liabilities	**(3)**	(2)
Employee benefit obligations	**(67)**	(65)

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

	2015	2014	**Estimated Amortization in 2016**
		(in millions)	
Prior service cost	**$ 2**	$ 3	**$ 1**
Net loss	**142**	148	**7**
Regulatory assets	**$ 144**	$ 151	

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

	2015	2014
	(in millions)	
Regulatory assets:		
Beginning balance	**$ 151**	$ 78
Net (gain) loss	**4**	79
Reclassification adjustments:		
Amortization of prior service costs	**(1)**	(1)
Amortization of net gain (loss)	**(10)**	(5)
Total reclassification adjustments	**(11)**	(6)
Total change	**(7)**	73
Ending balance	**$ 144**	$ 151

Components of net periodic pension cost were as follows:

	2015	2014	2013
		(in millions)	
Service cost	**$ 13**	$ 10	$ 11
Interest cost	**21**	20	18
Expected return on plan assets	**(33)**	(29)	(27)
Recognized net loss	**10**	5	10
Net amortization	**1**	1	1
Net periodic pension cost	**$ 12**	$ 7	$ 13

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

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

	Benefit Payments
	(in millions)
2016	$ 20
2017	21
2018	22
2019	24
2020	25
2021 to 2025	146

Other Postretirement Benefits

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

	2015	2014
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 96**	$ 81
Service cost	**1**	1
Interest cost	**4**	4
Benefits paid	**(5)**	(5)
Actuarial loss (gain)	**(1)**	14
Plan amendment	**1**	—
Retiree drug subsidy	**1**	1
Balance at end of year	**97**	96
Change in plan assets		
Fair value of plan assets at beginning of year	**24**	23
Actual return on plan assets	**—**	2
Employer contributions	**3**	3
Benefits paid	**(4)**	(4)
Fair value of plan assets at end of year	**23**	24
Accrued liability	**$ (74)**	$ (72)

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

	2015	2014
	(in millions)	
Other regulatory assets, deferred	**$ 21**	$ 18
Other regulatory liabilities, deferred	**(3)**	(2)
Employee benefit obligations	**(74)**	(72)

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

	2015	2014	**Estimated Amortization in 2016**
		(in millions)	
Prior service cost	**$ —**	$ (2)	**$ —**
Net (gain) loss	**(18)**	18	**1**
Net regulatory assets	**$ (18)**	$ 16	

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

	2015	2014
	(in millions)	
Net regulatory assets (liabilities):		
Beginning balance	**$ 16**	$ 2
Net (gain) loss	**—**	14
Change in prior service costs	**3**	—
Reclassification adjustments:		
Amortization of net gain (loss)	**(1)**	—
Total reclassification adjustments	**(1)**	—
Total change	**2**	14
Ending balance	**$ 18**	$ 16

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

	2015	2014	2013
		(in millions)	
Service cost	**$ 1**	$ 1	$ 1
Interest cost	**4**	4	4
Expected return on plan assets	**(2)**	(2)	(1)
Net amortization	**1**	—	—
Net periodic postretirement benefit cost	**$ 4**	$ 3	$ 4

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

	Benefit Payments	**Subsidy Receipts**	**Total**
		(in millions)	
2016	$ 6	$ —	$ 6
2017	6	(1)	5
2018	6	(1)	5
2019	7	(1)	6
2020	7	(1)	6
2021 to 2025	36	(2)	34

Benefit Plan Assets

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

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

	Target	**2015**	2014
Pension plan assets:			
Domestic equity	26%	**30%**	30%
International equity	25	**23**	23
Fixed income	23	**23**	27
Special situations	3	**2**	1
Real estate investments	14	**16**	14
Private equity	9	**6**	5
Total	100%	**100%**	100%
Other postretirement benefit plan assets:			
Domestic equity	21%	**24%**	24%
International equity	20	**18**	19
Domestic fixed income	38	**38**	41
Special situations	3	**2**	1
Real estate investments	11	**13**	11
Private equity	7	**5**	4
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, 2015 and 2014. The fair values presented are prepared in accordance with GAAP. For purposes of determining the fair value of the pension plan and other postretirement benefit plan assets and the appropriate level designation, management relies on information provided by the plan's trustee. This information is reviewed and evaluated by management with changes made to the trustee information as appropriate.

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

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

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

	Fair Value Measurements Using				
As of December 31, 2015:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Net Asset Value as a Practical Expedient (NAV)**	**Total**
			(in millions)		
Assets:					
Domestic equity*	$ 76	$ 32	$ —	$ —	$ 108
International equity*	55	46	—	—	101
Fixed income:					
U.S. Treasury, government, and agency bonds	—	21	—	—	21
Mortgage- and asset-backed securities	—	9	—	—	9
Corporate bonds	—	53	—	—	53
Pooled funds	—	23	—	—	23
Cash equivalents and other	—	7	—	—	7
Real estate investments	14	—	—	57	71
Private equity	—	—	—	30	30
Total	$ 145	$ 191	$ —	$ 87	$ 423

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

As of December 31, 2014:	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)	Net Asset Value as a Practical Expedient (NAV)	Total
			(in millions)		
Assets:					
Domestic equity*	$ 78	$ 32	$ —	$ —	$ 110
International equity*	49	45	—	—	94
Fixed income:					
U.S. Treasury, government, and agency bonds	—	32	—	—	32
Mortgage- and asset-backed securities	—	9	—	—	9
Corporate bonds	—	53	—	—	53
Pooled funds	—	24	—	—	24
Cash equivalents and other	—	30	—	—	30
Real estate investments	14	—	—	51	65
Private equity	—	—	—	26	26
Total	$ 141	$ 225	$ —	$ 77	$ 443

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

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

	Fair Value Measurements Using				
As of December 31, 2015:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Net Asset Value as a Practical Expedient (NAV)**	**Total**
			(in millions)		
Assets:					
Domestic equity*	$ 3	$ 1	$ —	$ —	$ 4
International equity*	2	2	—	—	4
Fixed income:					
U.S. Treasury, government, and agency bonds	—	6	—	—	6
Mortgage- and asset-backed securities	—	—	—	—	—
Corporate bonds	—	2	—	—	2
Pooled funds	—	1	—	—	1
Cash equivalents and other	1	—	—	—	1
Real estate investments	1	—	—	3	4
Private equity	—	—	—	1	1
Total	$ 7	$ 12	$ —	$ 4	$ 23

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

	Fair Value Measurements Using				
As of December 31, 2014:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Net Asset Value as a Practical Expedient (NAV)	Total
			(in millions)		
Assets:					
Domestic equity*	$ 3	$ 2	$ —	$ —	$ 5
International equity*	2	2	—	—	4
Fixed income:					
U.S. Treasury, government, and agency bonds	—	6	—	—	6
Mortgage- and asset-backed securities	—	—	—	—	—
Corporate bonds	—	2	—	—	2
Pooled funds	—	1	—	—	1
Cash equivalents and other	1	1	—	—	2
Real estate investments	1	—	—	2	3
Private equity	—	—	—	1	1
Total	$ 7	$ 14	$ —	$ 3	$ 24

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

Employee Savings Plan

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 2015, 2014, and 2013 were $5 million, $5 million, and $4 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 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

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 affected sites. The Company has authority from the Mississippi PSC to recover approved environmental compliance costs through regulatory mechanisms.

FERC Matters

Municipal and Rural Associations Tariff

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 $23 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.

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 2013, the Company received an order from the FERC accepting the settlement agreement.

In 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 2013. The 2013 settlement agreement provided that base rates under the MRA cost-based electric tariff will increase by approximately $24 million annually, effective April 1, 2013.

In March 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 in May 2014, provided that base rates under the MRA cost-based electric tariff increased approximately $10 million annually, effective May 1, 2014.

Included in this settlement agreement, an adjustment to the Company's wholesale revenue requirement in a subsequent rate proceeding was allowed in the event the Kemper IGCC, or any substantial portion thereof, was placed in service before or after December 1, 2014. Therefore, the Company recorded a regulatory asset as a result of a portion of the Kemper IGCC being placed in service prior to the projected date, which was fully amortized as of December 31, 2015.

On May 13, 2015, the FERC accepted a further settlement agreement between the Company and its wholesale customers to forgo a MRA cost-based electric tariff increase by, among other things, increasing the accrual of AFUDC and lowering the portion of CWIP in rate base, effective April 1, 2015. The additional resulting AFUDC is estimated to be approximately $14 million annually, of which $11 million relates to the Kemper IGCC.

Fuel Cost Recovery

The Company has a wholesale MRA and a Market Based (MB) fuel cost recovery factor. Effective January 1, 2016, the wholesale MRA fuel rate decreased $47 million annually. Effective February 1, 2016, the wholesale MB fuel rate decreased $2 million annually. At December 31, 2015, the amount of over-recovered wholesale MRA fuel costs included in the balance sheets was $24 million compared to an immaterial balance at December 31, 2014.

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.

Market-Based Rate Authority

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

Retail Regulatory Matters

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 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 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.

In June 2014, the Mississippi PSC approved the Company's 2014 Energy Efficiency Quick Start Plan filing, which includes a portfolio of energy efficiency programs. In November 2014, the Mississippi PSC approved the Company's revised compliance filing, which included an increase of $7 million in retail revenues for the period December 2014 through December 2015.

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 2013, the MPUS contested the Company's PEP lookback filing for 2012, which indicated a refund due to customers of $5 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 2013, the Mississippi PSC approved the projected PEP filing for 2013, which resulted in a rate increase of 1.9%, or $15 million, annually, effective March 19, 2013. The Company may be entitled to $3 million in additional revenues related to 2013 as a result of the late implementation of the 2013 PEP rate increase.

In March 2014 and 2015, the Company submitted its annual PEP lookback filings for 2013 and 2014, respectively, which each indicated no surcharge or refund. The Mississippi PSC suspended each of the filings to allow more time for review.

In June 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 were placed in service in November 2015. These units are jointly owned by the Company and Gulf Power, with 50% ownership each. 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, 2015, total project expenditures were $637 million, of which the Company's portion was $325 million, excluding AFUDC of $36 million.

In 2013, the Mississippi PSC approved the Company's 2013 ECO Plan filing which proposed no change in rates.

In August 2014, the Company entered into a settlement agreement with the Sierra Club that, among other things, required 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, which also occurred in August 2014. 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 (which occurred on April 16, 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.

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, 2015, $5 million of Plant Greene County costs and $36 million of costs related to Plant Watson have been reclassified as regulatory assets. 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 2016. 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.

On December 3, 2015, the Mississippi PSC approved the Company's revised ECO filing for 2015, which indicated no change in revenue.

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 Mississippi PSC approved the 2016 retail fuel cost recovery factor, effective January 21, 2016, which will result in an annual revenue decrease of approximately $120 million. At December 31, 2015, the amount of over-recovered retail fuel costs included in the balance sheets was $71 million compared to a $3 million under-recovered balance at December 31, 2014.

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 September 1, 2015, the Mississippi PSC approved the Company's annual ad valorem tax adjustment factor filing effective September 18, 2015, which included an annual rate decrease of 0.35%, or $2 million in annual retail revenues, primarily due to average millage rates.

System Restoration Rider

On October 6, 2015, the Mississippi PSC approved the Company's 2015 SRR rate filing, which proposed that the SRR rate remain level at zero and the Company continue to accrue $3 million annually to the property damage reserve.

On February 1, 2016, the Company submitted its 2016 SRR rate filing which proposed no changes to either the SRR rate or the annual property damage reserve accrual. The ultimate outcome of this matter cannot be determined at this time.

See Note 1 under "Provision for Property Damage" 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 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 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 using natural gas in August 2014 and currently expects to place the remainder of the Kemper IGCC, including the gasifier and the gas clean-up facilities, in service during the third quarter 2016.

Recovery of the costs subject to the cost cap and the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, AFUDC, and certain general exceptions, including change of law, force majeure, and beneficial capital (which exists when 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) remains 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 Mississippi Supreme Court's (Court) decision), and actual costs incurred as of December 31, 2015, are as follows:

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

(a) Amounts in the Current Cost Estimate reflect estimated costs through August 31, 2016.

(b) The 2012 MPSC CPCN Order approved a construction cost cap of up to \$2.88 billion, net of the DOE Grants and excluding the Cost Cap Exceptions. The Current Cost Estimate and the Actual Costs include non-incremental operating and maintenance costs related to the combined cycle and associated common facilities placed in service in August 2014 that are subject to the \$2.88 billion cost cap and exclude post-in-service costs for the lignite mine. See "Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order" herein for additional information. The Current Cost Estimate and the Actual Costs reflect 100% of the costs of the Kemper IGCC. See note (g) for additional information.

(c) 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." The current estimate reflects the impact of a settlement agreement with the wholesale customers for cost-based rates under FERC's jurisdiction. See "FERC Matters" herein for additional information.

(d) Incremental operating and maintenance costs related to the combined cycle and associated common facilities placed in service in August 2014, net of costs related to energy sales. See "Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order" herein for additional information.

(e) The 2012 MPSC CPCN Order approved deferral of non-capital Kemper IGCC-related costs during construction as described in "Rate Recovery of Kemper IGCC Costs – Regulatory Assets and Liabilities" herein.

(f) The 2010 Project Estimate is the certificated cost estimate adjusted to include the certificated estimate for the CO_2 pipeline facilities which was approved in 2011 by the Mississippi PSC.

(g) Beginning in the third quarter 2015, certain costs, including debt carrying costs (associated with assets placed in service and other non-CWIP accounts), that previously were deferred as regulatory assets are now being recognized through income; however, such costs continue to be included in the Current Cost Estimate and the Actual Costs at December 31, 2015.

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

The Company does not intend to seek rate recovery for any costs related to the construction of the Kemper IGCC that exceed the \$2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions. The Company recorded pre-tax charges to income for revisions to the cost estimate above the cost cap of \$365 million (\$226 million after tax), \$868 million (\$536 million after tax), and \$1.1 billion (\$681 million after tax) in 2015, 2014, and 2013, respectively. The increases to the cost estimate in

2015 primarily reflect costs for the extension of the Kemper IGCC's projected in-service date through August 31, 2016, increased efforts related to scope modifications, additional labor costs in support of start-up and operational readiness activities, and system repairs and modifications after startup testing and commissioning activities identified necessary remediation of equipment installation, fabrication, and design issues, including the refractory lining inside the gasifiers; the lignite feed and dryer systems; and the syngas cooler vessels. Any extension of the in-service date beyond August 31, 2016 is currently estimated to result in additional base costs of approximately $25 million to $35 million per month, which includes maintaining necessary levels of start-up labor, materials, and fuel, as well as operational resources required to execute start-up and commissioning activities. However, additional costs may be required for remediation of any further equipment and/or design issues identified. Any extension of the in-service date with respect to the Kemper IGCC beyond August 31, 2016 would also increase costs for the Cost Cap Exceptions, which are not subject to the $2.88 billion cost cap established by the Mississippi PSC. These costs include AFUDC, which is currently estimated to total approximately $13 million per month, as well as carrying costs and operating expenses on Kemper IGCC assets placed in service and consulting and legal fees of approximately $2 million per month. For additional information, see "2015 Rate Case" herein.

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

Rate Recovery of Kemper IGCC Costs

See "FERC Matters" herein 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 "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 future proceedings related to the operation of the Kemper IGCC. To the extent the Mississippi PSC determines the Kemper IGCC does not meet the operational parameters ultimately adopted by the Mississippi PSC or the Company incurs additional costs to satisfy such parameters, there could be a material adverse impact on the Company's financial statements.

2013 MPSC Rate Order

In January 2013, the Company entered into a settlement agreement with the Mississippi PSC that was intended to establish the process for resolving matters regarding cost recovery related to the Kemper IGCC (2013 Settlement Agreement). Under the 2013 Settlement Agreement, 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. In March 2013, the Mississippi PSC issued a rate order approving retail rate increases of 15% effective March 19, 2013 and 3% effective January 1, 2014, which collectively were designed to collect $156 million annually beginning in 2014 (2013 MPSC Rate Order) to be used to mitigate customer rate impacts after the Kemper IGCC is placed in service.

Because the 2013 MPSC Rate Order did not provide for the inclusion of CWIP in rate base as permitted by the Baseload Act, the Company continues to record AFUDC on the Kemper IGCC. 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.

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

2015 Rate Case

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

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

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

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

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

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

The Company expects to seek additional rate relief to address recovery of the remaining Kemper IGCC assets. In addition to current estimated costs at December 31, 2015 of $6.63 billion, 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.

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

Regulatory Assets and Liabilities

Consistent with the treatment of non-capital costs incurred during the pre-construction period, the Mississippi PSC issued an accounting order in 2011 granting 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.

In August 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. Beginning in the third quarter 2015, in connection with the implementation of interim rates, the Company began expensing certain ongoing project costs and certain debt carrying costs (associated with assets placed in service and other non-CWIP accounts) that previously were deferred as regulatory assets and began amortizing certain regulatory assets associated with assets placed in service and consulting and legal fees. The amortization periods for these regulatory assets vary from two years to 10 years as set forth in the In-Service Asset Rate Order. As of December 31, 2015, the balance associated with these regulatory assets was $120 million. Other regulatory assets associated with the remainder of the Kemper IGCC totaled $96 million as of December 31, 2015. The amortization period for these assets is expected to be determined by the Mississippi PSC in future rate proceedings following completion of construction and start-up of the Kemper IGCC and related prudence reviews.

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

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

Lignite Mine and CO_2 Pipeline Facilities

In conjunction with the Kemper IGCC, 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 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 Denbury and Treetop with termination rights as the Company has not satisfied its contractual obligation to deliver captured CO_2 by May 11, 2015. Since May 11, 2015, the Company has been engaged in ongoing discussions with its off-takers regarding the status of the CO_2 delivery schedule as well as other issues related to the CO_2 agreements. As a result of discussions with Treetop, on August 3, 2015, the Company agreed to amend certain provisions of their agreement that do not affect pricing or minimum purchase quantities. Potential requirements imposed on CO_2 off-takers under the Clean Power Plan (if ultimately enacted in its current form, pending resolution of litigation) and the potential adverse financial impact of low oil prices on the off-takers increase the risk that the CO_2 contracts may be terminated or materially modified. Any termination or material modification of these agreements could result in a material reduction in the Company's revenues to the extent the Company is not able to enter into other similar contractual arrangements. Additionally, if the contracts remain in place, sustained oil price reductions could result in significantly lower revenues than the Company forecasted to be available to offset customer rate impacts, which could have a material impact on the Company's financial statements.

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

Termination of Proposed Sale of Undivided Interest to SMEPA

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

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

Bonus Depreciation

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

Investment Tax Credits

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

Section 174 Research and Experimental Deduction

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

4. JOINT OWNERSHIP AGREEMENTS

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 $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" for additional information.

At December 31, 2015, 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	Accumulated Depreciation	CWIP
			(in millions)	
Greene County				
Units 1 and 2	40%	$ 152	$ 56	$ 13
Daniel				
Units 1 and 2	50%	$ 686	$ 160	$ 10

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.

5. INCOME TAXES

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

Current and Deferred Income Taxes

Details of income tax provisions are as follows:

	2015	2014	2013
		(in millions)	
Federal —			
Current	**$ (768)**	$ (431)	$ 23
Deferred	**704**	183	(343)
	(64)	(248)	(320)
State —			
Current	**(81)**	1	5
Deferred	**73**	(38)	(53)
	(8)	(37)	(48)
Total	**$ (72)**	$ (285)	$ (368)

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

	2015	2014
	(in millions)	
Deferred tax liabilities —		
Accelerated depreciation	**$ 1,618**	$ 1,068
ECM under recovered	**13**	—
Regulatory assets associated with AROs	**71**	19
Pensions and other benefits	**30**	35
Regulatory assets associated with employee benefit obligations	**66**	68
Regulatory assets associated with the Kemper IGCC	**86**	62
Rate differential	**115**	89
Federal effect of state deferred taxes	**—**	1
Fuel clause under recovered	**—**	3
Other	**163**	52
Total	**2,162**	1,397
Deferred tax assets —		
Fuel clause over recovered	**51**	—
Estimated loss on Kemper IGCC	**451**	631
Pension and other benefits	**92**	92
Property insurance	**25**	24
Premium on long-term debt	**18**	21
Unbilled fuel	**16**	15
AROs	**71**	19
Interest rate hedges	**4**	5
Kemper rate factor - regulatory liability retail	**—**	108
Property basis difference	**451**	263
ECM over recovered	**—**	1
Deferred state tax assets	**152**	57
Deferred federal tax assets	**48**	—
Federal effect of state deferred taxes	**8**	—
Other	**13**	15
Total	**1,400**	1,251
Total deferred tax liabilities, net	**762**	146
Deferred state tax asset	**—**	34
Accumulated deferred income taxes	**$ 762**	$ 180

On November 20, 2015, the FASB issued ASU 2015-17, which simplifies the presentation of deferred income taxes. The new guidance resulted in a reclassification from prepaid income taxes of $121 million with $105 million to non-current accumulated deferred income taxes and $16 million to other deferred charges in the Company's December 31, 2014 balance sheet. See Note 1 under "Recently Issued Accounting Standards" for additional information.

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

At December 31, 2015, the tax-related regulatory assets were $291 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, 2015, the tax-related regulatory liabilities were $8 million. These liabilities are primarily attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and 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 related deferred ITCs amortized in this manner amounted to $1 million in each of 2015, 2014, and 2013.

At December 31, 2015, the Company had state of Mississippi NOL carryforwards totaling approximately $3 billion, resulting in deferred tax assets of approximately $97 million. The NOLs will expire between 2033 and 2035, but are expected to be fully utilized by 2028.

Effective Tax Rate

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

	2015	2014	2013
Federal statutory rate	**(35.0)%**	(35.0)%	(35.0)%
State income tax, net of federal deduction	**(6.3)**	(4.0)	(3.7)
Non-deductible book depreciation	**1.3**	0.1	0.1
AFUDC-equity	**(49.6)**	(7.8)	(5.0)
Other	**(2.9)**	0.1	(0.1)
Effective income tax rate (benefit rate)	**(92.5)%**	(46.6)%	(43.7)%

The increase in the Company's 2015 effective tax rate (benefit rate), as compared to 2014, is primarily due to a decrease in estimated losses associated with the Kemper IGCC, offset by a decrease in non-taxable AFUDC equity. 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.

Unrecognized Tax Benefits

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

	2015	2014	2013
		(in millions)	
Unrecognized tax benefits at beginning of year	**$ 165**	$ 4	$ 6
Tax positions increase from current periods	**32**	58	—
Tax positions increase/(decrease) from prior periods	**224**	103	(2)
Balance at end of year	**$ 421**	$ 165	$ 4

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

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

	2015	2014	2013
		(in millions)	
Tax positions impacting the effective tax rate	**$ (2)**	$ 4	$ 4
Tax positions not impacting the effective tax rate	**423**	161	—
Balance of unrecognized tax benefits	**$ 421**	$ 165	$ 4

The tax positions impacting the effective tax rate for 2015 primarily relate to a graduated tax rate adjustment on the 2014 federal income tax return. The tax positions impacting the effective tax rate for 2014 and 2013 primarily relate to state income tax credits. The tax positions not impacting the effective tax rate for 2015 and 2014 relate to deductions for R&E expenditures associated with the Kemper IGCC. See "Section 174 Research and Experimental Deduction" herein for more information.

Accrued interest for unrecognized tax benefits was as follows:

	2015	2014	2013
		(in millions)	
Interest accrued at beginning of year	$ 3	$ 1	$ 1
Interest accrued during the year	6	2	—
Balance at end of year	$ 9	$ 3	$ 1

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

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

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

Section 174 Research and Experimental Deduction

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

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

6. FINANCING

Bank Term Loans

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

At December 31, 2015, the Company had a total of $900 million in bank loans outstanding including $475 million classified as notes payable and $425 million classified as securities due within one year. At December 31, 2014, the Company had $775 million in bank loans outstanding which are classified as securities due within one year.

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, 2015, the Company was in compliance with its debt limits.

Senior Notes

At December 31, 2015 and 2014, 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. 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 million, reflecting a premium of $76 million. See "Assets Subject to Lien" herein for additional information.

Securities Due Within One Year

A summary of scheduled maturities and redemptions of securities due within one year at December 31, 2015 and 2014 was as follows:

	2015	2014
	(in millions)	
Senior notes	**$ 300**	$ —
Bank term loans	**425**	775
Capitalized leases	**3**	3
Outstanding at December 31	**$ 728**	$ 778

Maturities through 2020 applicable to total long-term debt are as follows: $728 million in 2016, $614 million in 2017, $3 million in 2018, $128 million in 2019, and $10 million in 2020.

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, 2015 and 2014 was $83 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.

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

Capital Leases

In 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, 2015 and 2014 of $77 million and $80 million, respectively, with an annual interest rate of 4.9% for both years. 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 2015 were $7 million and will be $7 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.

Other Obligations

In June 2015, the Company issued an 18-month floating rate promissory note to Southern Company bearing interest based on LIBOR plus 1.25%. This note was for an aggregate principal amount of approximately $301 million, the amount paid by Southern Company to SMEPA pursuant to Southern Company's guarantee of the return of SMEPA's deposits. In December 2015, the $301 million promissory note was amended, which among other things, changed the maturity date to December 1, 2017 and changed the interest rate to be based on one-month LIBOR plus 1.50%. See Note 3 under "Integrated Coal Gasification Combined Cycle – Termination of Proposed Sale of Undivided Interest to SMEPA" for additional information.

In November 2015, the Company issued a 25-month floating rate promissory note to Southern Company bearing interest based on an adjusted LIBOR rate. At December 31, 2015, the adjusted LIBOR rate was equal to the one-month LIBOR plus 1.50%. This note was for an aggregate principal amount of up to $375 million. As of December 31, 2015 the Company had borrowed $275 million.

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. See "Plant Daniel Revenue Bonds" herein for additional information.

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. Information for each outstanding series is in the table below:

Preferred Stock	Par Value/ Stated Capital Per Share	Shares Outstanding	Redemption Price Per Share
4.40% Preferred Stock	$ 100	8,867	$ 104.32
4.60% Preferred Stock	$ 100	8,643	$ 107.00
4.72% Preferred Stock	$ 100	16,700	$ 102.25
5.25% Preferred Stock	$ 25	1,200,000	$ 25.00

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, 2015, committed credit arrangements with banks were as follows:

Expires			Executable Term-Loans		Due Within One Year	
2016	Total	Unused	One Year	Two Years	Term Out	No Term Out
(in millions)	*(in millions)*		*(in millions)*		*(in millions)*	
$220	$220	$195	$30	$15	$45	$175

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.

A portion of the $195 million unused credit with banks is allocated to provide liquidity support to the Company's 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, 2015 was $40 million.

At December 31, 2015 and 2014, there was no commercial paper debt outstanding.

At December 31, 2015, there was $500 million of short-term debt outstanding. At December 31, 2014, 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 2015, 2014, and 2013, the Company incurred fuel expense of $443 million, $574 million, and $491 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, 2015 of $38 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 $5 million, $10 million, and $10 million for 2015, 2014, and 2013, 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 $2 million in 2015, $3 million in 2014, and $3 million in 2013. The Company's annual railcar lease payments for 2016 through 2017 will average approximately $1 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 annually from 2013 through 2015; however, those amounts were immaterial for the reporting period. The Company's annual lease payments through 2020 are expected to be immaterial for fuel handling equipment. The Company charged to fuel stock and recovered through fuel cost recovery the barge transportation leases in the amount of $2 million in 2015, $8 million in 2014, and $7 million in 2013 related to barges and tow/shift boats. The Company has no future lease commitments with respect to these barge transportation leases.

8. STOCK COMPENSATION

Stock-Based Compensation

Stock-based compensation, in the form of Southern Company stock options and performance share units, may be granted through the Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. As of December 31, 2015, there were 231 current and former employees participating in the stock option and performance share unit programs.

Stock Options

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

For the years ended December 31, 2014 and 2013, employees of the Company were granted stock options for 578,256 shares and 345,830 shares, respectively. The weighted average grant-date fair value of stock options granted during 2014 and 2013 derived using the Black-Scholes stock option pricing model was $2.20 and $2.93, 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, 2015, 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, 2015, 2014, and 2013 was $3 million, $5 million, and $3 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $1 million, $2 million, and $1 million for the years ended December 31, 2015, 2014, and 2013, respectively. As of December 31, 2015, the aggregate intrinsic value for the options outstanding and options exercisable was $7 million and $5 million, respectively.

Performance Share Units

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

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

Beginning in 2015, Southern Company issued two additional types of performance share units to employees in addition to the TSR-based awards. These included performance share units with performance goals based on cumulative earnings per share (EPS) over the performance period and performance share units with performance goals based on Southern Company's equity-weighted ROE over the performance period. The EPS-based and ROE-based awards each represent 25% of total target grant date fair value of the performance share unit awards granted. The remaining 50% of the target grant date fair value consists of TSR-based awards. In contrast to the Monte Carlo simulation model used to determine the fair value of the TSR-based awards, the fair values of the EPS-based awards and the ROE-based awards are based on the closing stock price of Southern Company common stock on the date of the grant. Compensation expense for the EPS-based and ROE-based awards is generally recognized ratably over the three-year performance period initially assuming a 100% payout at the end of the performance period. The TSR-based performance share units, along with the EPS-based and ROE-based awards, issued in 2015, vest immediately upon the retirement of the employee. As a result, compensation expense for employees that are retirement eligible at the grant date is recognized immediately while compensation expense for employees that become retirement eligible during the vesting period is recognized over the period from grant date to the date of retirement eligibility. The expected payout related to the EPS-based and ROE-based awards is reevaluated annually with expense recognized to date increased or decreased based on the number of shares currently expected to be issued. Unlike the TSR-based awards, the compensation expense ultimately recognized for the EPS-based awards and the ROE-based awards will be based on the actual number of shares issued at the end of the performance period.

For the years ended December 31, 2015, 2014, and 2013, employees of the Company were granted performance share units of 53,909, 49,579, and 36,769, respectively. The weighted average grant-date fair value of TSR-based performance share units granted during 2015, 2014, and 2013, 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 \$46.41, \$37.54, and \$40.50, respectively. The weighted average grant-date fair value of both EPS-based and ROE-based performance share units granted during 2015 was \$47.77.

For the years ended December 31, 2015, 2014, and 2013, total compensation cost for performance share units recognized in income was \$4 million, \$2 million, and \$2 million, respectively, with the related tax benefit also recognized in income of \$2 million, \$1 million, and \$1 million, respectively. The compensation cost and tax benefits related to the grant 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, 2015, there was \$1 million of total unrecognized compensation cost related to performance share award units that will be recognized over a weighted-average period of approximately 19 months.

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

	Fair Value Measurements Using			
As of December 31, 2015:	**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:				
Cash equivalents	\$ 52	\$ —	\$ —	\$ 52
Liabilities:				
Energy-related derivatives	\$ —	\$ 47	\$ —	\$ 47

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

	Fair Value Measurements Using			
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:				
Cash equivalents	$ 115	$ —	$ —	$ 115
Liabilities:				
Energy-related derivatives	$ —	$ 45	$ —	$ 45

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.

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

	Carrying Amount	**Fair Value**
	(in millions)	
Long-term debt:		
2015	**$ 2,537**	**$ 2,413**
2014	$ 2,320	$ 2,382

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.

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

- *Regulatory Hedges* – Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the Company's fuel-hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the respective fuel cost recovery clauses.
- *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, 2015, the net volume of energy-related derivative contracts for natural gas positions totaled 32 million mmBtu for the Company, with the longest hedge date of 2018 over which the Company 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 income.

At December 31, 2015, there were no interest rate derivatives outstanding.

The estimated pre-tax losses that will be reclassified from accumulated OCI to interest expense for the next 12-month period ending December 31, 2016 are $1 million. The Company has deferred gains and losses that are expected to be amortized into earnings through 2022.

Derivative Financial Statement Presentation and Amounts

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

	Asset Derivatives			**Liability Derivatives**		
Derivative Category	**Balance Sheet Location**	**2015**	2014	**Balance Sheet Location**	**2015**	2014
		(in millions)			*(in millions)*	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	**$ —**	$ —	Other current liabilities	**$ 29**	$ 26
	Other deferred charges and assets	**—**	—	Other deferred credits and liabilities	**18**	19
Total derivatives designated as hedging instruments for regulatory purposes		**$ —**	$ —		**$ 47**	$ 45

Energy-related derivatives not designated as hedging instruments were immaterial for 2015 and 2014.

The Company's derivative contracts are not subject to master netting arrangements or similar agreements and are reported gross on the Company's financial statements. Some of these energy-related 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. At December 31, 2015 and 2014, energy-related derivatives presented in the table above did not have amounts available for offset.

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

	Unrealized Losses			Unrealized Gains		
Derivative Category	**Balance Sheet Location**	**2015**	2014	**Balance Sheet Location**	**2015**	2014
		(in millions)			*(in millions)*	
Energy-related derivatives:	Other regulatory assets, current	**$ (29)**	$ (26)	Other regulatory liabilities, current	**$ —**	$ —
	Other regulatory assets, deferred	**(18)**	(19)	Other regulatory liabilities, deferred	**—**	—
Total energy-related derivative gains (losses)		**$ (47)**	$ (45)		**$ —**	$ —

For the years ended December 31, 2015, 2014, and 2013, 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, 2015, 2014, and 2013, the pre-tax effects of derivatives designated as cash flow hedging instruments on the statements of operations were immaterial.

There was no material ineffectiveness recorded in earnings for any period 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, 2015, the Company's collateral posted with its derivative counterparties was immaterial.

At December 31, 2015, the fair value of derivative liabilities with contingent features was $12 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 $52 million, and include certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade.

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

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.

11. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2015 and 2014 is as follows:

Quarter Ended	Operating Revenues	Operating Income (Loss)	Net Income (Loss) After Dividends on Preferred Stock
		(in millions)	
March 2015	**$ 276**	**$ 24**	**$ 35**
June 2015	**275**	**12**	**49**
September 2015	**341**	**(66)**	**(21)**
December 2015	**246**	**(143)**	**(71)**
March 2014	$ 331	$ (325)	$ (172)
June 2014	311	56	62
September 2014	355	(349)	(195)
December 2014	246	(71)	(24)

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 $183 million ($113 million after tax) in the fourth quarter 2015, $150 million ($93 million after tax) in the third quarter 2015, $23 million ($14 million after tax) in the second quarter 2015, $9 million ($6 million after tax) in the first quarter 2015, $70 million ($43 million after tax) in the fourth quarter 2014, $418 million ($258 million after tax) in the third quarter 2014, and $380 million ($235 million after tax) in the first quarter 2014. See Note 3 under "Integrated Coal Gasification Combined Cycle" for additional information.

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

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	2015	2014	2013	2012	2011
Operating Revenues (in millions)	**$ 1,138**	$ 1,243	$ 1,145	$ 1,036	$ 1,113
Net Loss After Dividends on Preferred Stock (in millions)	**$ (8)**	$ (329)	$ (477)	$ 100	$ 94
Cash Dividends on Common Stock (in millions)	**$ —**	$ —	$ 72	$ 107	$ 76
Return on Average Common Equity (percent)	**(0.34)**	(15.43)	(24.28)	7.14	10.54
Total Assets (in millions)[(a)(b)]	**$ 7,840**	$ 6,642	$ 5,822	$ 5,334	$ 3,631
Gross Property Additions (in millions)	**$ 972**	$ 1,389	$ 1,773	$ 1,665	$ 1,206
Capitalization (in millions):					
Common stock equity	**$ 2,359**	$ 2,084	$ 2,177	$ 1,749	$ 1,049
Redeemable preferred stock	**33**	33	33	33	33
Long-term debt[(a)]	**1,886**	1,621	2,157	1,561	1,096
Total (excluding amounts due within one year)	**$ 4,278**	$ 3,738	$ 4,367	$ 3,343	$ 2,178
Capitalization Ratios (percent):					
Common stock equity	**55.1**	55.8	49.9	52.3	48.2
Redeemable preferred stock	**0.8**	0.9	0.7	1.0	1.5
Long-term debt[(a)]	**44.1**	43.3	49.4	46.7	50.3
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	**153,158**	152,453	152,585	152,265	151,805
Commercial	**33,663**	33,496	33,250	33,112	33,200
Industrial	**467**	482	480	472	496
Other	**175**	175	175	175	175
Total	**187,463**	186,606	186,490	186,024	185,676
Employees (year-end)	**1,478**	1,478	1,344	1,281	1,264

(a) A reclassification of debt issuance costs from Total Assets to Long-term debt of $9 million, $11 million, $4 million, and $8 million is reflected for years 2014, 2013, 2012, and 2011, respectively, in accordance with ASU 2015-03. See Note 1 under "Recently Issued Accounting Standards" for additional information.

(b) A reclassification of deferred tax assets from Total Assets of $105 million, $16 million, $36 million, and $34 million is reflected for years 2014, 2013, 2012, and 2011, respectively, in accordance with ASU 2015-17. See Note 1 under "Recently Issued Accounting Standards" for additional information.

	2015	2014	2013	2012	2011
Operating Revenues (in millions):					
Residential	**$ 238**	$ 239	$ 242	$ 227	$ 247
Commercial	**256**	257	266	251	263
Industrial	**287**	291	289	263	276
Other	**(5)**	8	2	6	7
Total retail	**776**	795	799	747	793
Wholesale — non-affiliates	**270**	323	294	256	273
Wholesale — affiliates	**76**	107	35	16	30
Total revenues from sales of electricity	**1,122**	1,225	1,128	1,019	1,096
Other revenues	**16**	18	17	17	17
Total	**$ 1,138**	$ 1,243	$ 1,145	$ 1,036	$ 1,113
Kilowatt-Hour Sales (in millions):					
Residential	**2,025**	2,126	2,088	2,046	2,162
Commercial	**2,806**	2,860	2,865	2,916	2,871
Industrial	**4,958**	4,943	4,739	4,702	4,586
Other	**40**	40	40	38	39
Total retail	**9,829**	9,969	9,732	9,702	9,658
Wholesale — non-affiliates	**3,852**	4,191	3,929	3,819	4,010
Wholesale — affiliates	**2,807**	2,900	931	572	649
Total	**16,488**	17,060	14,592	14,093	14,317
Average Revenue Per Kilowatt-Hour (cents)[(a)]:					
Residential	**11.75**	11.26	11.59	11.09	11.40
Commercial	**9.12**	8.99	9.27	8.60	9.17
Industrial	**5.79**	5.89	6.10	5.59	6.01
Total retail	**7.90**	7.97	8.21	7.70	8.21
Wholesale	**5.20**	6.06	6.76	6.19	6.52
Total sales	**6.80**	7.18	7.73	7.23	7.66
Residential Average Annual Kilowatt-Hour Use Per Customer	**13,242**	13,934	13,680	13,426	14,229
Residential Average Annual Revenue Per Customer	**$ 1,556**	$ 1,568	$ 1,585	$ 1,489	$ 1,622
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**3,561**	3,867	3,088	3,088	3,156
Maximum Peak-Hour Demand (megawatts):					
Winter	**2,548**	2,618	2,083	2,168	2,618
Summer	**2,403**	2,345	2,352	2,435	2,462
Annual Load Factor (percent)	**60.6**	59.4	64.7	61.9	59.1
Plant Availability Fossil-Steam (percent)[(b)]	**90.6**	87.6	89.3	91.5	87.7
Source of Energy Supply (percent):					
Coal	**16.5**	39.7	32.7	22.8	34.9
Oil and gas	**81.6**	55.3	57.1	63.9	51.5
Purchased power —					
From non-affiliates	**0.4**	1.4	2.0	2.0	1.4
From affiliates	**1.5**	3.6	8.2	11.3	12.2
Total	**100.0**	100.0	100.0	100.0	100.0

(a) The average revenue per kilowatt-hour (cents) is based on booked operating revenues and will not match billed revenue per kilowatt-hour.

(b) Beginning in 2012, plant availability is calculated as a weighted equivalent availability.

DIRECTORS AND OFFICERS
Mississippi Power Company 2015 Annual Report

Directors

Carl J. Chaney
Vice Chairman, JTS Capital Group
New York, New York. Elected 2009

L. Royce Cumbest
Chairman, President, and Chief Executive Officer
Merchants & Marine Bank and Merchants & Marine Bancorp, Inc.
Pascagoula, Mississippi. Elected 2010

Thomas A. Dews
President
C. L. Dews & Sons Foundry and Machinery Co., Inc.
Hattiesburg, Mississippi. Elected 2013

G. Edison Holland, Jr.
Chairman of the Board
Mississippi Power Company
Gulfport, Mississippi. Elected 2013

Mark E. Keenum
President
Mississippi State University
Mississippi State, Mississippi. Elected 2013

Christine L. Pickering
Christy Pickering, CPA Public Accounting Firm
Biloxi, Mississippi. Elected 2007

Philip J. Terrell, Ph.D.
Retired Superintendent of Schools
Pass Christian Public School District
Pass Christian, Mississippi. Elected 1995

Marion L. Waters
Partner
Waters International Trucks, Inc., Waters Trucks and Tractor Co., Inc., and Waters Transportation, Inc.
Meridian, Mississippi. Elected 2010

Anthony L. Wilson
President and Chief Executive Officer
Mississippi Power Company
Gulfport, Mississippi. Elected 2015

Officers

G. Edison Holland, Jr.
Chairman of the Board, President, and Chief Executive Officer (Resigned as President effective 10/19/15 and Chief Executive Officer effective 12/31/15)

Anthony L. Wilson
President and Chief Executive Officer
(Elected President effective 10/19/15 and Chief Executive Officer effective 1/1/16)

John W. Atherton
Vice President of Corporate Services and Community Relations

A. Nicole Faulk
Vice President of Customer Services Organization
(Elected effective 5/2/15)

Moses H. Feagin
Vice President, Treasurer, and Chief Financial Officer

Michael A. Hazelton
Vice President of Customer Services Organization
(Elected effective 4/1/15)
(Resigned effective 5/2/15)

R. Allen Reaves
Vice President and Senior Production Officer

Billy F. Thornton
Vice President of External Affairs

Emile J. Troxclair III
Vice President of Kemper Development

Cynthia F. Shaw
Comptroller

Vicki L. Pierce
Corporate Secretary and Assistant Treasurer

Stacy R. Kilcoyne
Vice President

Melissa K. Caen
Assistant Secretary and Assistant Treasurer

General
This annual report is submitted for general information. It is not intended for use in connection with any sale or purchase of, or any solicitation of offers to buy or sell, securities.

Profile
The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located within the State of Mississippi and to wholesale customers in the Southeast. The Company sells electricity to approximately 187,000 customers. In 2015, retail energy sales accounted for 59.6% of the Company's total sales of 16.5 billion kilowatt-hours.

The Company is a wholly-owned subsidiary of The Southern Company, which is the parent company of four traditional operating companies, a wholesale generation subsidiary, and other direct and indirect subsidiaries.

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150 East 42nd Street
40th Floor
New York, NY 10017
(917) 260-1534

There is no market for the Company's common stock, all of which is owned by The Southern Company.

Dividends on the Company's common stock are payable at the discretion of the Company's board of directors. The dividends declared by the Company to its common stockholder for the past two years were as follows:

Quarter	2015	2014
	(in thousands)	
First	--	$54,930
Second	--	54,930
Third	--	54,930
Fourth	--	54,930

Number of Preferred Shareholders of record as of December 31, 2015 was 194.

Form 10-K
A copy of Form 10-K as filed with the Securities and Exchange Commission will be provided upon written request to the office of the Corporate Secretary at the Corporate Office address below.

Corporate Office
Mississippi Power Company
2992 West Beach Boulevard
Gulfport, Mississippi 39501
(228) 864-1211

Auditors
Deloitte & Touche LLP
Suite 2000
191 Peachtree Street, N.E.
Atlanta, Georgia 30303

Legal Counsel
Balch & Bingham LLP
P.O. Box 130
Gulfport, Mississippi 39502

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