santee cooper®

LIGHTING *the* PATH

2014 ANNUAL REPORT

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Note: Immaterial rounding variances may occur throughout this report.

CHAIRMAN AND CEO LETTER

With a continued, steady focus on financial stability, economic development and customer service, the decisions and progress Santee Cooper made in 2014 are lighting the path toward a robust, successful future.

Santee Cooper continues to be financially stable and financially strategic. In June and October, we completed sales of a total $1.38 billion in revenue obligation bonds, which will be used primarily to help finance Santee Cooper's share of costs to build two new nuclear power units at V.C. Summer Nuclear Station and to restructure or refund a portion of existing debt. Through strategic debt restructuring, we realized annual savings of $79 million.

Operationally, we continued to achieve excellent system reliability results including a distribution reliability rate of 99.9966 percent, a transmission reliability rate of 99.9986 percent, and a generation availability factor of 90.02 percent. Our debt-to-equity ratio for 2014 was 75/25. Santee Cooper also began providing power to Piedmont Municipal Power Association and to Alabama Municipal Electric Agency.

Excellent customer service for our more than 171,500 retail customers remains a priority for Santee Cooper. We worked tirelessly to bring power back to more than 45,000 customers less than four days after the February 12 arrival of Winter Storm Pax, which made the largest impact on our system since Hurricane Hugo in 1989.

Continuing efforts to help our customers save energy, Santee Cooper introduced several new Reduce The Use initiatives. In the spring, we began offering free, online home energy checkups with EnergyEarth, making it easier for customers to learn where they can save energy in their homes. In October, Santee Cooper gave away 30,000 LED bulbs to residential customers to promote the benefits of the highly efficient bulbs. Our Reduce The Use residential and commercial programs create savings for customers that will last for years.

We partnered with York, Palmetto and Aiken electric cooperatives to install and dedicate three more Green Power Solar Schools, bringing our total to 26 Green Power Solar Schools statewide. Each Solar School is equipped with a 2-kilowatt solar array and a specialized curriculum, allowing students to study the opportunities and challenges of solar energy. Green Power Solar Schools are just one way Santee Cooper fulfills its commitment to reinvest Green Power funds back into renewable resources across South Carolina.

Santee Cooper also is studying solar on a larger scale with the 3-megawatt Colleton Solar Farm, which was dedicated in January in partnership with the state's electric cooperatives and TIG Sun Energy. Santee Cooper purchases electricity from the solar farm, which TIG built and operates and which increases the renewable generation available to our customers. We continue to analyze its generation data to learn how to better integrate utility-scale solar power into a complex power system.

We advanced economic opportunity last year in several ways, such as awarding $25.0 million in loans to projects throughout the state. New manufacturing announcements last year included tenants in Dillon, Marion and Orangeburg counties announcing hundreds of new jobs at plants under construction in late 2014.

In April, the Santee Cooper Board of Directors also approved two site readiness grant programs, totaling $42.5 million, designed to recruit industry and create jobs across South Carolina.

Specifically, the South Carolina Power Team Site Readiness Fund will award grants totaling up to $6.0 million a year for high-value projects in areas served by the state's electric cooperatives. The new $2.5-million-a-year Santee Cooper Municipal Site Readiness Fund will offer grants for high-value projects in municipalities served as wholesale customers by Santee Cooper. Both funds are available for five years.

The board also approved in April a new economic development rate to help attract eligible new or expanded large industry by offering savings on their initial electric bills. The rate is designed to provide the most benefit over the crucial start-up years. To qualify, industries must meet a required 2 MW of new electric load and make a $500,000-per-MW capital investment or hire at least 50 new employees.

One of our most significant accomplishments is being played out on the environmental front, specifically in our ash ponds. In March, we expanded our decades-long practice of recycling ash and gypsum by beginning a concentrated effort to remove the coal ash stored in seven ponds at Jefferies, Winyah and Grainger generating stations for beneficial use. Utilizing both longstanding and new technologies and processes, the ash will be used by the concrete and cement industries, a practice that is supported by the U. S. Environmental Protection Agency. In 2014, Santee Cooper removed more than 229,000 tons of fly ash and 319,000 tons of pond ash from its generating stations.

Unfortunately, the EPA proposed a carbon dioxide emissions rule in 2014 that has the potential to significantly increase South Carolina customers' bills primarily because it gives the state no credit for emissions reductions we would gain from new nuclear power units under construction. Santee Cooper educated customers about the proposed rule. We asked customers to share concerns with EPA, and Santee Cooper forwarded more than 36,000 postcards from customers to EPA. The common thread: Give South Carolina proper credit for emissions reductions we are already working on, especially new nuclear power units.

With partners South Carolina Electric & Gas, construction is continuing on those two new nuclear units at V.C. Summer Nuclear Station. When complete, the units will bring 2,200 MW of reliable, emissions-free electricity to the state's grid. Nuclear power is the only baseload resource that is emissions-free.

As we plan for the future, Santee Cooper will remain innovative and forward-thinking in order to continue providing low-cost, reliable, environmentally responsible power and water to our customers and to fulfill our mission of improving the quality of life for the people of South Carolina.

W. Leighton Lord III
Chairman

Lonnie N. Carter
President and CEO

CORPORATE STATISTICS

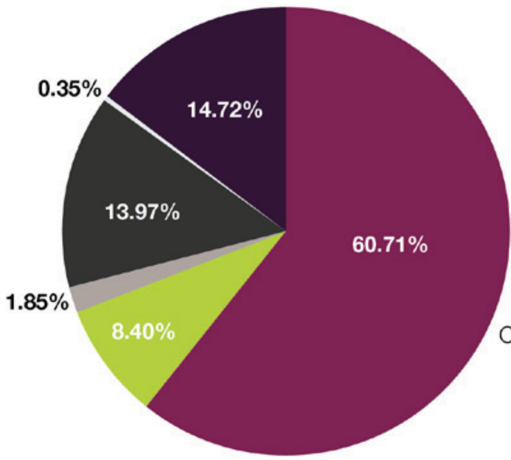
SYSTEM DATA 2014

Miles of transmission system lines:	4,992
Miles of distribution system lines:	2,806
Number of transmission substations:	104
Number of distribution substations:	53
Number of CEPCI Delivery Points (DPs):	468

(This total includes DPs for the 5 Upstate cooperatives served through Duke Energy system)

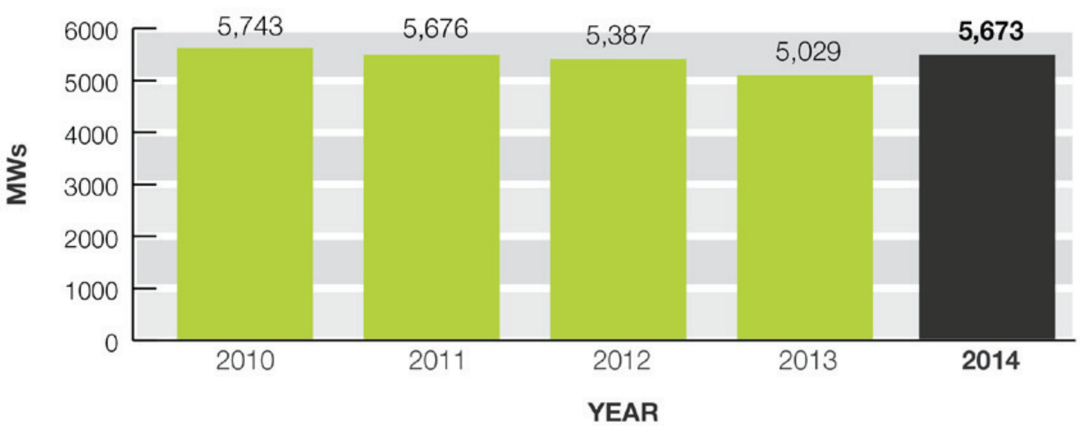
	2014	2013	2012	2011	2010
FINANCIAL (Thousands)					
Total Revenues & Income	**$ 2,023,414**	$ 1,823,502	$ 1,897,135	$ 1,923,828	$ 1,895,194
Total Expenses & Interest Charges	**1,894,217**	1,744,960	1,801,813	1,778,892	1,753,711
Other	**19,798**	7,396	9,155	5,987	(26,468)
Reinvested Earnings	**148,995**	85,938	104,477	150,923	115,015
OTHER FINANCIAL					
(Excluding commercial paper and other)					
Debt Service Coverage (Prior to Distribution to the State)	**1.53**	1.52	1.44	1.61	1.58
Debt / Equity Ratio	**75/25**	75/25	73/27	73/27	74/26
STATISTICAL					
Number of Customers (at Year-End)					
Retail Customers	**171,567**	168,813	166,809	164,647	163,601
Military and Large Industrial	**28**	29	29	29	30
Wholesale	**4**	4	4	4	4
Total Customers	**171,599**	168,846	166,842	164,680	163,635
Generation (GWh)					
Coal	**16,607**	13,949	15,888	20,048	21,889
Nuclear	**2,297**	2,788	2,421	2,469	2,828
Hydro	**506**	624	271	274	450
Natural Gas & Oil	**3,821**	4,315	4,710	3,817	2,918
Landfill Gas & Renewables	**96**	115	103	115	108
Total Generation (GWh)	**23,327**	21,791	23,393	26,723	28,193
Purchases, Net Interchanges, etc. (GWh)	**4,738**	5,335	4,099	1,546	940
Wheeling, Interdepartmental, and Losses	**(712)**	(762)	(736)	(717)	(951)
Total Energy Sales (GWh)	**27,353**	26,364	26,756	27,552	28,182
Summer Maximum Continuous Rating (MCR) Generating Capability (MW)	**5,182**	5,183	5,665	5,665	5,662
Territorial Peak Demand (MW)	**5,673**	5,029	5,387	5,676	5,743

2014 GENERATION BY FUEL MIX

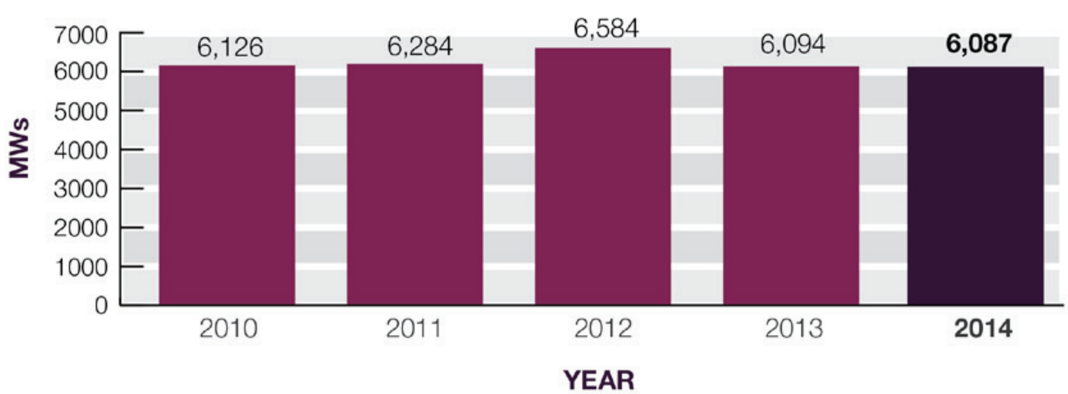


Source		GWh
COAL	60.71%	16,607
NUCLEAR	8.40%	2,297
HYDRO	1.85%	506
NATURAL GAS & OIL	13.97%	3,821
OTHER RENEWABLES	0.35%	96
PURCHASES (NET)	14.72%	4,026
	100.00%	27,353

PEAK DEMAND



TOTAL SUMMER CAPABILITY (MCR) WITH FIRM PURCHASES



AUDIT COMMITTEE CHAIRWOMAN'S LETTER

The Audit Committee of the Board of Directors is comprised of independent directors Peggy H. Pinnell – Chairwoman, William A. Finn, Merrell W. Floyd, Catherine E. Heigel, Dan J. Ray and Jack F. Wolfe Jr.

The committee receives regular reports from members of management and Internal Audit regarding their activities and responsibilities.

The Audit Committee oversees Santee Cooper's financial reporting, internal controls and audit process on behalf of the board of directors.

Periodic financial statements and reports pertaining to operations and representations were received from management and the internal auditors. In fulfilling its responsibilities, the committee also reviewed the overall scope and specific plans for the respective audits by the internal auditors and the independent public accountants. The committee discussed the company's financial statements and the adequacy of its system of internal controls. The committee met with the independent public accountants and with the General Auditor to discuss the results of the audit, the evaluation of Santee Cooper's internal controls, and the overall quality of Santee Cooper's financial reporting.

Peggy H. Pinnell

Peggy H. Pinnell
Chairwoman
2014 Audit Committee

Notes:
Cecil E. Viverette and Kristofer D. Clark also served on the 2014 Audit Committee. Cecil E. Viverette's term on the Board ended effective May 1, 2014, and Kristofer D. Clark rotated off the committee as of June 23, 2014.

William A. Finn, Merrell W. Floyd, Catherine E. Heigel, Dan J. Ray and Jack F. Wolfe Jr. joined the committee effective June 23, 2014.

MANAGEMENT'S DISCUSSION AND ANALYSIS of Financial Condition and Results of Operations

INTRODUCTION

The South Carolina Public Service Authority (the Authority or Santee Cooper) is a component unit of the State of South Carolina (the State), created by the State in 1934 for the purpose of providing and aiding interstate commerce, navigation, electric power and wholesale water to the people of South Carolina. The statute under which it was created provides that the Authority will establish rates and charges so as to produce revenues sufficient to provide for payment of all expenses, the conservation, maintenance and operation of its facilities and properties and the payment of the principal and interest on its notes, bonds, or other obligations. Provided, however, that prior to putting into effect any increase in rates the Authority shall give at least a sixty day notice of such increase to all customers who will be affected.

The Authority's assets include wholly owned and ownership interests in a variety of coal, natural gas, nuclear, hydro, biomass, landfill and solar generating units totaling 5,182 megawatts (MW) of summer power supply peak capability. This consists of 3,480 MW of coal-fired capacity, 1,226 MW of natural gas and oil capacity, 318 MW of nuclear capacity, 129 MW of hydro capacity and 29 MW of landfill methane gas capacity. In addition, the Authority may purchase from, sell to or exchange with other bulk electric suppliers additional capacity and energy in order to maximize the efficient use of generating resources, reduce operating costs and increase operating revenues.

The Authority and South Carolina Electric & Gas (SCE&G) are parties to a joint ownership agreement to own and operate the Virgil C. Summer Nuclear Plant (Summer Nuclear) Unit 1 with undivided interests of 33 1/3 and 66 2/3 percent, respectively. In order to further diversify its fuel mix, the Authority has an ownership interest in two 1,117 MW, net nuclear generating units under construction at Summer Nuclear. The Authority also operates an integrated transmission system which includes lines owned by the Authority as well as those owned by Central Electric Power Cooperative (Central), the Authority's largest cost of service customer.

Questions concerning any of the information provided in this report or requests for additional information should be addressed to Glenda Gillette, Vice President and Controller, South Carolina Public Service Authority, P.O. Box 2946101, Moncks Corner, SC 29461-2901.

OVERVIEW OF THE COMBINED FINANCIAL STATEMENTS

This discussion serves as an introduction to the basic combined financial statements of the Authority to provide the reader with an overview of the Authority's financial position and operations. As discussed in the notes to the Combined Financial Statements (Note 1 - B "System of Accounts"), the combined financial statements include the accounts of the Lake Moultrie and Lake Marion Regional Water Systems.

The Combined Statements of Net Position summarize information on the Authority's assets, deferred outflows of resources, liabilities, deferred inflows of resources and net position.

The operating results of the Authority are presented in the Combined Statements of Revenues, Expenses and Changes in Net Position. Revenues represent billings for electricity sold and fuel expense (see Note 1 - O, "Revenue Recognition and Fuel Costs"), as well as wholesale water sales. Expenses primarily include operating costs and debt service related charges.

The Combined Statements of Cash Flows are presented using the direct method. This method provides broad categories of cash receipts and cash disbursements related to cash provided by or used in operations, non-capital related financing, capital related financing and investing activities.

The Notes are an integral part of the Authority's basic combined financial statements and provide additional information on certain components of these statements.

Financial Condition Overview

The Authority's Combined Statements of Net Position as of December 31, 2014, 2013 and 2012 are summarized below:

	2014	2013	2012
		(Thousands)	
ASSETS & DEFERRED OUTFLOWS OF RESOURCES			
Capital assets	**$ 6,917,786**	$ 6,375,051	$ 5,947,918
Current assets	**2,837,902**	2,808,713	2,288,238
Other noncurrent assets	**1,248,905**	1,384,597	1,353,413
Deferred outflows of resources	**203,638**	139,235	172,963
Total assets & deferred outflows of resources	**$ 11,208,231**	$ 10,707,596	$ 9,762,532
LIABILITIES & DEFERRED INFLOWS OF RESOURCES			
Long-term debt - net	**$ 6,639,162**	$ 6,456,379	$ 5,413,319
Current liabilities	**1,031,382**	892,044	1,072,061
Other noncurrent liabilities	**1,160,723**	1,125,051	1,102,894
Deferred inflows of resources	**208,501**	193,995	199,675
Total liabilities & deferred inflows of resources	**$ 9,039,768**	$ 8,667,469	$ 7,787,949
NET POSITION			
Net invested in capital assets	**$ 957,835**	$ 895,969	$ 894,920
Restricted for debt service	**108,457**	92,662	140,038
Restricted for capital projects	**6,515**	0	0
Unrestricted	**1,095,656**	1,051,496	939,625
Total net position	**$ 2,168,463**	$ 2,040,127	$ 1,974,583
Total liabilities, deferred inflows of resources & net position	**$ 11,208,231**	$ 10,707,596	$ 9,762,532

2014 Compared to 2013

The primary changes in the Authority's combined financial condition as of December 31, 2014 and 2013 were as follows:

Assets and Deferred Outflows of Resources

Total assets and deferred outflows of resources increased $500.6 million during 2014 due to increases of $542.7 million in capital assets, $29.2 million in current assets and $64.4 million in deferred outflows of resources. Offsetting these increases were reductions in other noncurrent assets of $135.7 million.

The increase in capital assets was due to net construction work in progress and utility plant increases of $612.2 million and $156.4 million, respectively. These increases resulted from construction costs associated with Summer Nuclear Units 2 and 3 as well as construction projects at several generating facilities and on the transmission system. Offsetting these increases were retirements of $43.6 million. Further reductions were caused by accumulated depreciation increasing $182.1 million and a small reduction in other physical property.

The increase in current assets was due primarily to net additions of $180.1 million in restricted cash, cash equivalents and investments resulting from the 2014 bond activity impact, construction payments and debt service payments. Fossil fuel inventory decreased $113.4 million due to increased fossil generation and delays in coal transportation. Nuclear fuel inventory decreased $12.6 million due to amortization expense for fuel burned at Summer Nuclear Unit 1. The remaining $24.9 million was a decrease resulting from the net change in unrestricted cash, cash equivalents, investments, receivables, materials inventory, interest receivable and prepaid expenses and other current assets.

The decrease in other noncurrent assets was due to a reduction in other noncurrent and regulatory assets resulting from the receipt of $231.9 million from the Santee River Flooding case settlement. Further reductions resulted from a change in deferred interest receivable of $13.5 million related to the sale of 5% of Summer Nuclear Units 2 and 3. Offsetting these reductions was $7.9 million in net additions related to the transfer of Pee Dee costs as well as $8.4 million more in billable projects. The asset retirement obligation increased $56.5 million due to accretion on nuclear and ash pond assets. Restricted cash, cash equivalents and investments rose $12.4 million resulting from investment income and market value adjustments. Further increases were provided by higher costs to be recovered from future revenues (CTBR) of $19.8 million from the 2014 bond activity and lower depreciation rates. The remaining variance was due to changes in the other accounts in this category.

The increase in deferred outflows of resources was due to a larger accumulated decrease in fair value of hedging derivatives and higher unamortized loss on refunded and defeased debt of $50.6 million and $13.8 million, respectively. The higher reduction in accumulated decrease in fair value of hedging derivatives was due to increased mark-to-market losses driven by lower natural gas prices during 2014. The larger unamortized loss on refunded and defeased debt was due to amortization, additions and removals from current year bond activity.

Liabilities, Deferred Inflows of Resources & Net Position

Liabilities & deferred inflows of resources increased $372.3 million due to increases of $182.8 million in long-term debt-net, $139.3 million in current liabilities, $35.7 million in other noncurrent liabilities and $14.5 million in deferred inflows of resources.

Long-term debt-net increased $182.8 million due to net additions of $85.6 million in total long-term debt and $97.2 million in unamortized debt discounts and premiums. The increase in long-term debt was due to additions of $1,420.9 million from the 2014 bond activity. Offsetting this was a decrease of $556.1 million for transfers to current portion of long-term debt and $779.2 million due to defeasance or refunding activity. Unamortized debt discounts and premiums increased due to net additions of $144.1 million from the 2014 bond activity. Offsetting this were decreases of $22.0 million for amortization of discounts and premiums and $24.9 million for removals from refunding bond activity.

The increase in current liabilities was due to $38.1 million for commercial paper, $36.8 million for natural gas hedging losses, additional manual accruals for Summer Nuclear Units 2 and 3 construction, Summer Nuclear Unit 1 fuel and other generating station outages of $42.1 million as well as a $26.5 million higher Central Cost of Service (COS) adjustment between the periods. Additional changes were caused by increases in the current portion of long-term debt of $16.0 million and a reduction in accrued interest on long-term debt of $21.1 million. Other smaller changes resulted in the residual variance.

Other noncurrent liabilities increased due to changes in the asset retirement obligation liability of $19.4 million due to accretion on nuclear and ash pond liabilities, as well as net noncurrent hedging losses of $11.7 million. Increases were also noted in Summer Nuclear pension and other post-employment benefits (OPEB) liabilities of $3.6 million, construction liabilities of $2.8 million, as well as deferred emission credit sales of $2.5 million. These increases were offset by a decrease in the noncurrent liability of $6.2 million for a maintenance agreement for the Rainey generating station. Net increases among the remaining accounts make up the residual variance.

Deferred inflows of resources increased due to higher nuclear decommissioning costs of $21.5 million resulting from market value adjustments, amortization and interest accruals for decommissioning funds. Offsetting this increase was $7.0 million reduction in accumulated increase in fair value of hedging derivatives caused by differing market conditions between the periods.

The main drivers for the overall increase in net position were higher net invested in capital assets and unrestricted of $61.9 million and $44.2 million, respectively. The increase in net invested in capital assets was due to higher construction work in progress, utility plant and the asset retirement obligation. Offsetting this increase was higher long-term debt and accumulated depreciation. Restricted for debt service also increased $15.8 million due to changes in accrued interest on long-term debt and reductions in the bond and debt service funds. An addition of non-borrowed funds for the Lake Moultrie Water System capacity upgrade of $6.5 million caused an increase in restricted for capital projects.

2013 Compared to 2012

The primary changes in the Authority's combined financial condition as of December 31, 2013 and 2012 were as follows:

Assets and Deferred Outflows of Resources

Total assets and deferred outflows of resources increased $945.1 million during 2013 due to increases of $427.1 million in capital assets, $520.5 million in current assets and $31.2 million in other noncurrent assets. Offsetting these increases were reductions in deferred outflows of resources of $33.7 million.

The increase in utility plant was due to construction work in progress and utility plant increases of $457.1 million and $189.2 million, respectively. These increases resulted from construction costs associated with Summer Nuclear Units 2 and 3, as well as construction projects at several generating facilities and on the transmission system. Offsetting these increases were retirements of $23.2 million. Further reductions were caused by accumulated depreciation increasing $195.5 million and a small reduction in other physical property.

The increase in current assets was due to additions of $490.1 million in unrestricted and restricted cash, cash equivalents and investments resulting from the 2013 bond activity impact on construction funds and the net impact of changes in revenue and operating funds from operating activities. Nuclear fuel inventory increased $78.7 million due to purchases and accruals, offset by amortization expense for fuel burned at Summer Nuclear Unit 1. The remaining $48.3 million was a decrease resulting from the net change in receivables, materials inventory, fossil fuel inventory, interest receivable and prepaid expenses and other current assets.

Other noncurrent assets increased due to a higher asset retirement obligation of $59.1 million resulting from accretion on nuclear and ash pond assets. CTBR increased $7.4 million due to the 2013 bond activity. Unamortized debt expense also increased $3.5 million as a result of net additions for current year bond activity. Offsetting these increases were reductions of $34.9 million from changes in investment in associated companies and other noncurrent and regulatory assets. A reduction in restricted cash, cash equivalents and investments of $3.9 million in the Nuclear Decommissioning Trust was also realized due to the net impact of additional funding and investment activity.

The decrease in deferred outflows of resources was due to reductions in unamortized loss on refunded and defeased debt and accumulated decrease in fair value of hedging derivatives of $18.2 million and $15.5 million, respectively. The reduction of unamortized loss on refunded and defeased debt was due to amortization, additions, and removals from current year bond activity whereas the reduction of accumulated decrease in fair value of hedging derivatives was due to a reduced loss value and roll off of legacy hedges in 2013.

Liabilities, Deferred Inflows of Resources & Net Position

Liabilities & deferred inflows of resources increased $879.5 million due to increases of $1,043.1 million in long-term debt-net and $22.2 million in other noncurrent liabilities. These increases were offset by reductions of $180.0 million in current liabilities and $5.7 million in deferred inflows of resources.

Net long-term debt increased due to additions in long-term debt of $1,090.9 million resulting from 2013 bond activity and long-term nuclear fuel payable for Summer Nuclear Unit 3. Offsetting this was a decrease in unamortized debt discounts and premiums of $47.8 million due to amortization, additions and removals related to current year bond activity.

Current liabilities decreased due to a reduction of $201.2 million in current portion of long-term debt and $8.3 million in accrued interest on long-term debt as a result of principal and interest payments and refunding bond activity. Accounts payable also decreased by $12.8 million. Offsetting these decreases was a $42.8 million increase in commercial paper resulting from net issues of $284.9 million and payments of $242.1 million. The remaining change of approximately $500,000 is associated with other current liabilities.

Other noncurrent liabilities increased due to the change in the asset retirement obligation liability of $21.9 million for accretion on nuclear and ash pond liabilities. Construction fund liabilities also increased by $1.2 million as a result of activity related to environmental projects. This was partially offset by a decrease of approximately $900,000 in other credits and noncurrent liabilities.

Deferred inflows of resources decreased due to a reduction in nuclear decommissioning costs of $10.4 million resulting from additional funding and net investment activity including market value adjustments. Offsetting this decrease was a $4.7 million change in accumulated increase in fair value of hedging derivatives caused by differing market conditions between the periods.

Net position increased by $65.5 million due to increases of $1.0 million in net invested in capital and $111.9 million in unrestricted. This was offset by a $47.4 million decrease in restricted for debt service. The change in net invested in capital was from increases in capital assets, long-term debt and commercial paper related to capital assets, and asset retirement obligation, offset by a decrease in current portion of long-term debt related to capital assets. The increase in unrestricted resulted mainly from changes in unrestricted investments, nuclear fuel inventory, current portion of long-term debt and commercial paper related to noncapital assets. Decreases offsetting these amounts were in unrestricted cash and cash equivalents, fossil fuel inventories, other noncurrent assets, and long-term debt related to noncapital assets. Restricted for debt service decreased due to a reduction in bond funds resulting from additional funding for future debt service and actual debt service payments.

Results of Operations

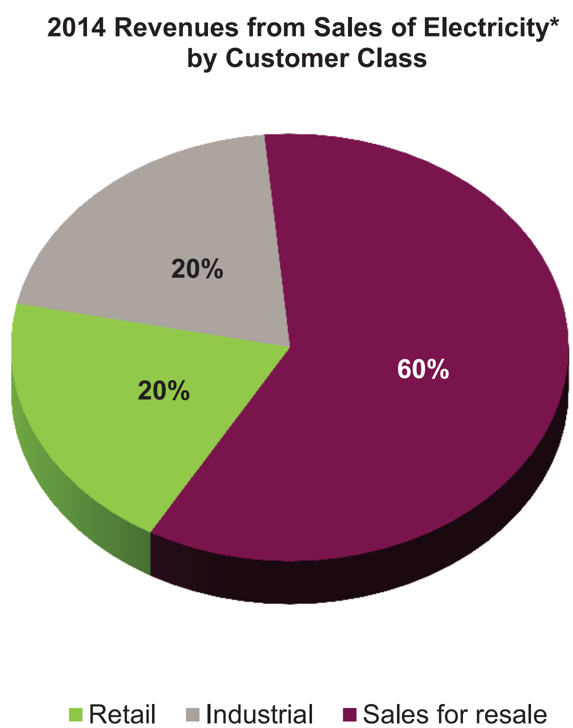
Santee Cooper's Combined Statements of Revenues, Expenses and Changes in Net Position for the years ended December 31, 2014, 2013 and 2012 are summarized as follows:

	2014	2013	2012
		(Thousands)	
Operating revenues	**$ 1,997,347**	$ 1,816,576	$ 1,887,797
Operating expenses	**1,619,224**	1,524,182	1,571,480
Operating income	**378,123**	292,394	316,317
Interest expense	**(274,993)**	(220,778)	(230,333)
Costs to be recovered from future revenue	**19,798**	7,396	9,155
Other income	**26,067**	6,926	9,338
Capital contributions & transfers	**(20,659)**	(20,394)	(19,625)
Change in net position	**$ 128,336**	$ 65,544	$ 84,852
Ending net position	**$ 2,168,463**	$ 2,040,127	$ 1,974,583

2014 Compared to 2013

Operating Revenues

As compared to 2013, combined operating revenues increased $180.8 million (10%). The driver for this increase was higher kWh sales (4%) and demand usage (5%). Partially offsetting this increase was lower demand and O&M rate revenues. Energy sales for 2014 totaled approximately 27.4 million megawatt hours (MWh) compared to approximately 26.4 million MWh's for 2013 with increases in all categories except industrial.

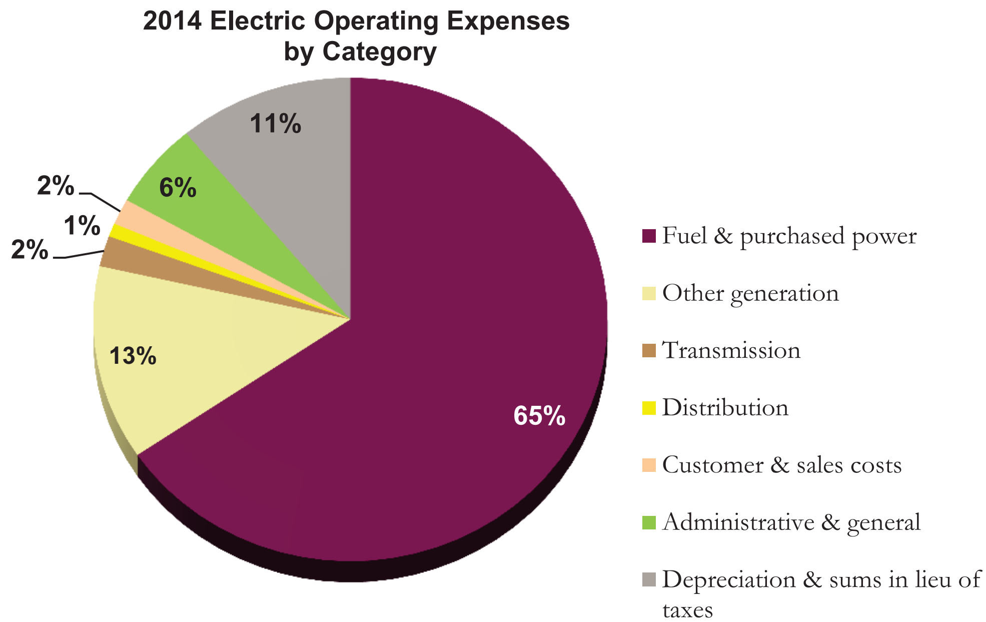


	2014	2013	2012
Revenues from Sales of Electricity*		(Thousands)	
Retail	**$ 394,195**	$ 355,598	$ 334,399
Industrial	**399,817**	381,689	389,742
Sales for resale	**1,181,350**	1,058,943	1,144,224
Totals	**$ 1,975,362**	$ 1,796,230	$ 1,868,365

*Excludes interdepartmental sales of $488 for 2014, $442 for 2013 and $444 for 2012.

Operating Expenses

Combined operating expenses for 2014 increased $95.0 million (6%) as compared to 2013. Fuel and purchased power increased by $99.3 million due to higher kWh sales associated with weather impacts, along with a shift in the economic dispatch due to station outages and higher prices in the energy markets. Non-fuel generation was higher by $14.3 million from expenses related to contract services, materials and Summer Nuclear Unit 1 expenses, as well as customer and sales costs being up by $6.3 million as a result of the accrual of economic development grants. Offsetting these increases was a decrease in administrative and general of $2.9 million resulting from contract services and insurance expense. Depreciation expense also decreased by $23.1 million from catch-up depreciation recorded in 2013 and the impact of the new depreciation rates implemented in 2014. The remaining variance was attributable to the net of the remaining categories being higher than prior year.



		2014		2013		2012
Electric Operating Expenses				(Thousands)		
Fuel & purchased power	**$**	**1,057,907**	$	958,566	$	990,434
Other generation		**210,083**		195,788		222,714
Transmission		**32,998**		32,211		31,612
Distribution		**14,503**		14,439		15,285
Customer & sales costs		**27,994**		21,672		21,463
Administrative & general		**92,967**		95,839		94,451
Depreciation & sums in lieu of taxes		**178,037**		201,143		191,469
Totals	**$**	**1,614,489**	$	1,519,658	$	1,567,428

NET BELOW THE LINE ITEMS

- Other income increased by $19.1 million over 2013 from interest received on the Santee River Flooding case settlement.
- Interest expense for 2014 was $54.2 million higher than 2013 resulting from the 2013 and 2014 bond activity impacts.
- CTBR changed $12.4 million due to a combination of bond activity and lower depreciation rates.
- The $265,000 increase in capital contributions & transfers represents dollars paid to the State. This payment is based on a percentage of total budgeted revenues which was higher in the 2014 budget compared to the 2013 budget.

2013 COMPARED TO 2012

OPERATING REVENUES

Compared to 2012, combined operating revenues decreased $71.2 million (4%). This was due to lower electric fuel rate revenues, kWh sales, demand usage and the cumulative impact between the 2013 and 2012 COS adjustments. Energy sales for 2013 totaled 26.4 million megawatt hours (MWh) compared to approximately 26.8 million MWh's for 2012 with decreases in all categories except retail.

OPERATING EXPENSES

Combined operating expenses for 2013 reflected a net decrease of $47.3 million (3%) compared to 2012. Fuel and purchased power expenses decreased by $31.9 million due to higher nuclear generation in the fuel mix. Non-fuel generation was lower by $26.9 million from expenses related to labor, materials and contract services. Offsetting these variances was an increase in administration and general by $1.4 million resulting from labor and benefits. Depreciation expense and sums in lieu of taxes increased $9.7 million due primarily to unitization of prior years' assets. The net difference for the remaining categories is approximately $400,000 higher than the prior year.

NET BELOW THE LINE ITEMS

- Other income decreased $2.4 million due to less interest income and a 2012 gain on sale of coal cars with no similar transaction in 2013.
- Interest charges for 2013 were $9.5 million lower than 2012 resulting from the impact of the 2013 bond activity.
- CTBR expense increased by $1.8 million as compared to prior year due to the lower depreciation and principal components resulting from the 2013 refunding and improvement bond activity.
- The $769,000 increase in capital contributions & transfers represents dollars paid to the State. This payment is based on a percentage of total budgeted revenues which was higher in the 2013 budget compared to the 2012 budget.

ECONOMIC CONDITIONS

The Authority and the electric industry continued to face economic and industry challenges that impact the competitiveness and financial condition of the utility. As market conditions fluctuate, the Authority's mission is to deliver low-cost and reliable electricity to its customers.

To address these challenges, the Authority has developed business growth initiatives that revolve around four strategic initiatives - marketing, product development, project management and competitive rates. The Authority is marketing industrial and commercial properties that are served directly by the Authority and its cooperative and municipal customers. Product development activities include the creation and/or improvement of industrial properties, the acquisition of property, expansion of infrastructure into industrial properties, and/or constructing buildings for industrial uses. Since June 2012, the Authority has invested over $50.0 million throughout South Carolina in product development through low-interest revolving loan programs to public entities. During 2014, the Authority created two additional funds for the purpose of providing potential industrial sites in cooperative and municipal territories, directly or indirectly served by Santee Cooper. Approved to date are more than $2.0 million from the municipal site readiness fund and over $3.0 million from the industrial site readiness fund. The Authority has also added a new economic development rate, the Experimental Large Light and Power Economic Development Service Tiered Rider, in addition to its existing economic development rider. Both rates are targeted at attracting new and expanding industrial loads and are available to the Authority's direct served industrial loads and are to be passed through to the Authority's wholesale customers located in South Carolina.

The Authority's largest customer is Central and accounted for 56.6% of sales revenues. Central provides wholesale electric service to each of the 20 distribution cooperatives (Central Cooperatives) which are members of Central pursuant to long-term all requirements power supply agreements. In September 2009 Central and the Authority entered into an agreement (September 2009 Agreement) that, among other things, provides for Central to transition a portion of the power and energy requirements of the five former Saluda members (Upstate Load) directly connected to the transmission system of Duke Energy Carolinas, LLC (Duke Energy) to another supplier and in January 2013, Central began transitioning the Upstate Load to Duke Energy. The September 2009 Agreement provides for approximately 15% of the Upstate Load to transition to Duke Energy annually between 2013 – 2018, with the remaining 10% of the Upstate Load transitioning to Duke Energy in 2019. By the end of the transition in 2019 the Upstate Load transferred will amount to approximately 900 Megawatts (MW). Nothing would preclude the Authority from serving this load when the Duke Energy agreement ends on December 31, 2030.

The Authority and Central continue to work cooperatively to better align their future interests and formalize how they will jointly plan for new resources. As part of this, Central agreed to extend their rights to terminate the agreement in the September 2009 Agreement until December 31, 2058. Under the Central Agreement 10-year rolling notice provision, for a termination date of December 31, 2058, a party must give notice of termination no later than December 31, 2048. Central has entered into requirement agreements with all 20 of its member cooperatives that extend through December 31, 2058 and obligate those members to pay their share of Central's costs, including costs paid under the Central Agreement. This amendment also provides more stability and certainty to the credit agencies as they rate the Authority's bonds going forward.

CAPITAL IMPROVEMENT PROGRAM

The purpose of the capital improvement program is to continue to meet the energy and water needs of the Authority's customers with economical and reliable service. The Authority's three-year budget for the capital improvement program approved in 2014, 2013 and 2012 was as follows:

	2014	2013	2012
	Budget 2015-17	Budget 2014-16	Budget 2013-15
Capital Improvement Expenditures		(Thousands)	
Environmental compliance	**$ 66,198**	$ 118,668	$ 165,300
General improvements to the system	**655,502**	596,558	666,700
Summer Nuclear Units 2 and 3	**1,677,228**	1,737,609	1,783,100
Totals	**$ 2,398,928**	$ 2,452,835	$ 2,615,100

As determined by the Authority, the cost of the capital improvement program will be provided from revenues, additional revenue obligations, commercial paper and other short-term obligations.

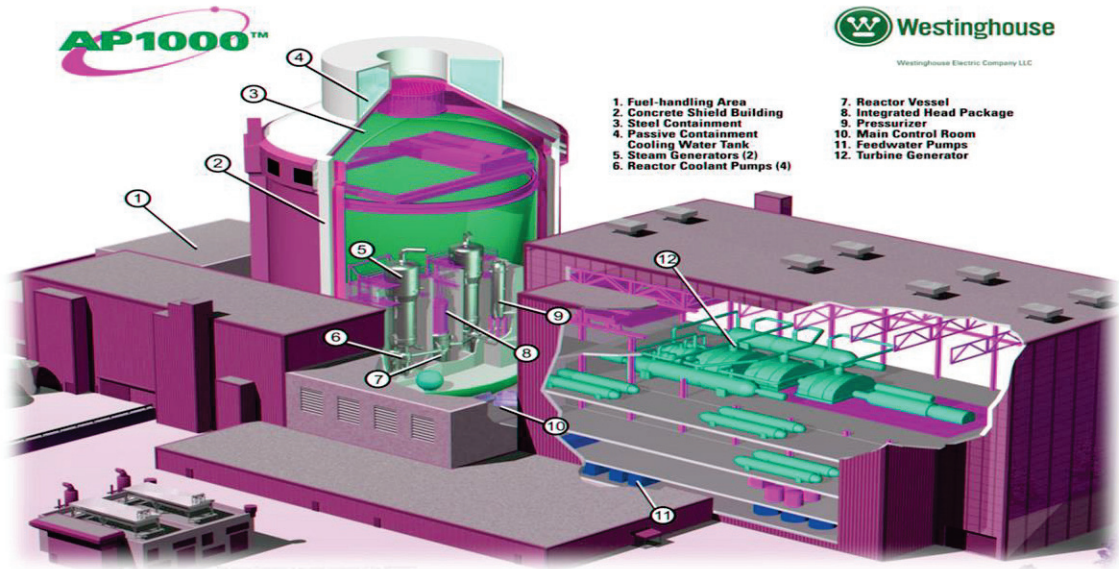
Summer Nuclear Units 2 and 3

Technology - Summer Nuclear Units 2 and 3 will consist of two Westinghouse AP1000 nuclear reactors, four low profile sixteen-cell mechanical draft cooling towers, intake and discharge structures, a 230 kV switchyard for transmission access, and numerous ancillary structures supporting the power generation process.

On January 27, 2006, the NRC approved the AP1000 standard plant design and issued its original AP1000 Design Certification Rule (DCR) which incorporated Revision 15 of the AP1000 Design Control Document (DCD).

On December 30, 2011, the NRC amended its regulations to certify an amendment to the AP1000 standard plant design incorporated in DCD Revisions 16 through 19. The amendment replaces the combined license information items and design acceptance criteria (DAC) with specific design information, addresses the effects of the impact of a large commercial aircraft, incorporates design improvements, and increases standardization of the design.

The AP1000 is the first and only reactor in its class of technological development, referred to as "Generation III+", to receive certification from the NRC.



The AP1000 is a pressurized water reactor with passive safety systems which, according to Westinghouse, in case of design basis accidents are designed to achieve a safe shutdown without operator action, AC power, or pumps.

Licensing - In March 2008, the Authority and SCE&G submitted to the NRC an application for Combined Construction and Operating Licenses (COLs) for Summer Nuclear Units 2 and 3. On March 30, 2012, the NRC concluded its mandatory hearing process for the application and found the NRC staff's review adequate to make the necessary regulatory safety and environmental findings, clearing the way for the formal issuance of the COLs. The COLs were issued by the NRC and received by SCE&G and the Authority on March 30, 2012.

The NRC's findings concluding the mandatory hearing process imposed two conditions on the COLs, with the first requiring inspection and testing of squib valves, important components of the reactor's passive cooling system. The second requires the development of strategies to respond to extreme natural events resulting in the loss of power at the new reactors. The NRC also directed the Office of New Reactors to issue to SCE&G and the Authority, simultaneously with the COLs, an Order requiring enhanced, reliable spent fuel pool instrumentation, as well as a request for information related to emergency plant staffing.

Engineering, Procurement, and Construction Agreement - On May 23, 2008, SCE&G, acting for itself and as agent for the Authority, entered into an Engineering, Procurement, and Construction (EPC) Agreement, with a Consortium consisting of Westinghouse Electric Company, LLC and Stone & Webster, Inc. Pursuant to the EPC Agreement, the Consortium will supply, construct, test, and start up two 1,117 MW nuclear generating units utilizing Westinghouse's AP1000 standard plant design. Under the EPC Agreement, the Authority will pay, in proportion to its ownership interest, a contract price that is subject to certain fixed price escalations and adjustments, adjustments for change orders and performance bonuses, and adjustments for cost overruns. A majority of the EPC Agreement costs are fixed or firm. In addition to EPC Agreement costs, the Authority will pay, in proportion to its ownership interest, costs associated with ancillary project facilities, staffing, project management and oversight by SCE&G and the Authority. The Authority estimates the current total construction cost associated with a 45% ownership interest to be approximately $5.1 billion including related transmission and initial nuclear fuel cores.

The EPC Agreement provides the Authority and SCE&G are jointly and severally liable for obligations under the EPC Agreement, to the extent such joint and several liability does not conflict with State law applicable to the Authority. Current State law provides the Authority shall be severally liable, in proportion to its joint ownership interest, for the acts, omissions, obligations performed, omitted, or incurred by SCE&G acting as agent for the Authority in constructing, operating or maintaining the Summer Units, but is not otherwise liable, jointly or severally for SCE&G's acts or omissions.

The EPC Agreement provides for certain liquidated damages upon the Consortium's failure to comply with schedule and performance guarantees, as well as certain bonuses payable to the Consortium for unit performance. The Consortium's liability for liquidated damages and for warranty claims is subject to a cap. The payment obligations of Westinghouse are guaranteed by Toshiba Corporation, and the payment obligations of Stone & Webster are guaranteed by Chicago Bridge & Iron Company. The Authority and SCE&G may, at any time, terminate the EPC Agreement for their convenience and without cause, provided that the Authority and SCE&G will pay certain termination costs and, at certain stages of the work, termination fees to the Consortium. The Consortium may terminate the EPC Agreement under certain circumstances, including (i) either SCE&G or the Authority's failure to make payment to Consortium in accordance with the EPC Agreement requirements, (ii) either SCE&G or the Authority's breach of a material provision of the EPC Agreement, or (iii) either SCE&G or the Authority's insolvency unless the other of SCE&G or the Authority has provided security for payments that would be due from such insolvent entity.

Ownership Agreements - On October 20, 2011, the Authority and SCE&G entered into a Design and Construction Agreement specifying an Authority ownership interest of 45% in each of Summer Nuclear Unit 2 and Summer Nuclear Unit 3. Among other things, the Design and Construction Agreement allows either or both parties to withdraw from the project under certain circumstances. Also on October 20, 2011, the Authority and SCE&G entered into an Operating and Decommissioning Agreement with respect to the two units. Both the Design and Construction Agreement and the Operating and Decommissioning Agreement define the conditions under which the Authority or SCE&G may convey an undivided ownership interest in the units to a third party.

Recent Developments - In January 2014, the Authority entered into an agreement whereby SCE&G will purchase from the Authority an additional 5% interest in the project. Under the terms of the agreement, SCE&G will own 60% of the new nuclear units and the Authority, 40%. The 5% ownership interest will be acquired in three stages, with 1% to be acquired at the commercial operation date of the first new nuclear unit, an additional 2% to be acquired no later than the first anniversary of such commercial operation date and the final 2% to be acquired no later than the second anniversary of such commercial operation date. The purchase price will be equal to the Authority's actual cost, including financing costs, of the percentage conveyed as of the date of the conveyance. The total purchase price is estimated to be between $500 and $600 million. The agreement will not impact the payment obligation for the full 45% ownership during construction. Under the terms of agreement with SCE&G the Authority cannot enter into an agreement to sell an additional portion of its 40% ownership interest until both units have been completed. However, the Authority is free to explore power sale opportunities from the facility.

Construction - Phase I - Phase I of the work consisted of the Consortium's engineering support and other services required by SCE&G and the Authority to support licensing efforts for Summer Nuclear Units 2 and 3 (including receipt of approvals from the PSC), continuation for design work, project management, engineering and administrative support to procure long lead time equipment, construction mobilization, site preparation, site infrastructure development, and installation of construction facilities. Phase I commenced May 23, 2008, with execution of the EPC Agreement, and was completed April 17, 2012 with SCE&G and the Authority's issuance of Full Notice to Proceed following receipt of the COLs.

Construction - Phase II - Phase II of the work consists of the remainder of the work required to supply, construct, test, and start up two AP1000 nuclear power plant units as is consistent with the AP1000 certified design. Phase II work is progressing and several key construction milestones have been achieved for Summer Nuclear Units 2 and 3.

Unit(s)	Construction Milestone	Date
Units 2 & 3	Energized Switchyard	February 1, 2013
Unit 2	Placed Nuclear Island Basemat (First Nuclear Concrete)	March 11, 2013
Unit 2	Set Module CR10 (Containment Vessel Bottom Head Support)	April 3, 2013
Unit 2	Set Containment Vessel Bottom Head	May 22, 2013
Unit 2	Set Structural Module CA04 (Reactor Vessel Cavity)	September 27, 2013
Unit 3	Placed Nuclear Island Basemat (First Nuclear Concrete)	November 4, 2013
Unit 2	Set Structural Module CA20 (Auxiliary Building Module)	May 9, 2014
Unit 3	Set Containment Vessel Bottom Head	May 21, 2014
Unit 2	Set Containment Vessel Ring 1	June 2, 2014
Unit 2	Set Structural Module CA05	December 6, 2014

Schedule - During the course of activities under the EPC Agreement, issues have materialized that have impacted project budget and schedule. The parties to the EPC Agreement have established both informal and formal dispute resolution procedures to resolve issues that arise during the course of constructing a project of this magnitude.

Claims specifically relating to COL delays, design modifications of the shield building and certain prefabricated structural modules and unanticipated rock conditions at the site resulted in assertions of contractual entitlement to recover additional costs to be incurred. On July 11, 2012, SCE&G, on behalf of itself and as agent for the Authority, agreed to a settlement with the Consortium which set the Authority's portion of the costs for these specific claims at approximately $113 million (in 2007 dollars). As a result of this settlement, the substantial completion dates for Summer Nuclear Units 2 and 3 changed from April 2016 and January 2019 (respectively) to March 2017 and May 2018.

Subsequent to July 2012, the Consortium has experienced delays in the schedule for fabrication and delivery of sub-modules for the new units. After examination of this issue and consultation with the Consortium, in June 2013, SCE&G announced that the substantial completion of Summer Nuclear Unit 2 was expected to be delayed from March 2017 to late 2017 or the first quarter of 2018 and the substantial completion for Summer Nuclear Unit 3 was expected to be similarly delayed. The dates have not been accepted as revised contractual substantial completion dates.

Since August 2013, the Consortium has experienced additional delays in sub-module fabrication and deliveries. The fabrication and delivery of sub-modules for Summer Nuclear Unit 2 are a focus area of the Consortium, including sub-modules for module CA20, which is part of the auxiliary building, and CA01, which houses components inside the containment vessel. Modules CA20 and CA01 are considered critical path items for both new units. All sub-modules for CA20 have been received on site, assembly completed, and the module placed on the nuclear island in May 2014. The delivery schedule of the sub-modules for CA01 is expected to support completion of on-site fabrication to allow it to be ready for placement on the nuclear island during the first half of 2015.

During the fourth quarter of 2013, the Consortium began a full re-baselining of the Unit 2 and Unit 3 construction schedules to incorporate project delays associated with incomplete engineering and late submodule fabrication and deliveries. The result will be a revised fully integrated project schedule.

In early August 2014, SCE&G and the Authority received preliminary schedule information in which the Consortium indicated the substantial completion of Unit 2 is expected to occur in late 2018 or the first half of 2019 and that the substantial completion of Unit 3 may be approximately 12 months later.

Since receiving the August 2014 preliminary schedule information, SCE&G and the Authority received a preliminary cost estimate associated with the schedule delays. The estimate to achieve a late 2018 substantial completion date totaled $1.176 billion for non-firm and non-fixed scopes of work. In addition to delay-related costs, this figure included project scope modifications currently under review by the Owners. This figure was presented as a total project cost in 2007 dollars subject to escalation and does not reflect consideration of the delay liquidated damages provisions of the EPC agreement which would partly mitigate any such delay-related costs.

SCE&G and the Authority have worked with Consortium executive management to evaluate this information. Based upon this evaluation, the Consortium has indicated that the Unit 2 substantial completion date is expected to occur by June 2019 and that the substantial completion date of Unit 3 may be approximately 12 months later. SCE&G and the Authority are continuing discussions with Consortium executive management in order to identify potential mitigation strategies to accelerate the substantial completion dates of the units and are working to arrive at an acceptable revised schedule and cost estimate.

Summary of Substantial Completion Dates

	Unit 2	**Unit 3**
Original EPC - May 2008	April 2016	January 2019
EPC - COL Delay - July 2012	March 2017 (+11 months)	May 2018 (-8 months)
Proposed Module Delay - June 2013	December 2017 - March 2018 (+9 to +12 months)	March 2019 (+10 months)
Proposed Re-baselined Schedule - August 2014*	December 2018 - June 2019 (+12 to +15 months)	June 2020 (+15 months)

* Currently under review by the Owners.

Other Project Developments - In addition to the above-described project issues, the Authority is also aware of financial difficulties that have been experienced by Mangiarotti S.p.A. (Mangiarotti), an Italy based supplier responsible for certain significant components of the project. Since first becoming aware of these financial difficulties, the Consortium has monitored the potential for disruptions in such equipment fabrication and possible responses. In September 2014, Westinghouse Electric Company completed the acquisition of Mangiarotti, in order to secure this supplier. To date, seven components have been received on site from Mangiarotti and three are in transit and expected to arrive at the site in February 2015. The remaining two components are in fabrication and expected to be received on-site during the first half of 2015.

Nuclear Construction, Risk Factors - The construction of large generating plants such as Summer Nuclear Units 2 and 3 involves significant financial risk. Delays or cost overruns may be incurred as a result of risks such as (a) inconsistent quality of equipment, materials and labor, (b) work stoppages, (c) regulatory matters, (d) unforeseen engineering problems, (e) unanticipated increases in the cost of materials and labor, (f) performance by engineering, procurement, or construction contractors and (g) increases in the cost of debt. Moreover, no nuclear plants have been constructed in the United States using advanced designs such as the Westinghouse AP1000 reactor. Therefore, estimating the cost of construction of any new nuclear plant is inherently uncertain.

To mitigate risk, SCE&G, acting for itself and as agent for the Authority, provides project oversight for Summer Nuclear Units 2 and 3 through its New Nuclear Deployment (NND) business unit. The Authority provides dedicated on-site personnel to monitor and assist NND with the daily oversight of the project. The managerial framework of the NND group is comprised of in-house nuclear industry veterans who lead various internal departments with expertise in: nuclear operations, engineering, construction, maintenance, quality assurance and nuclear regulations. This expertise is dispatched locally to monitor on site construction as well as domestically (and abroad) to provide surveillance at all major equipment manufacturers. In addition, NND representatives make frequent visits and work closely with the Consortium to monitor progress and issues (engineering, labor, supplier issues, etc.) associated with the AP1000 nuclear power units currently under construction in China, as well as the AP1000 units currently under development at nearby Plant Vogtle in Waynesboro, Georgia.

Financing Activities

Traditionally, the Authority has amortized its debt taking into consideration the potential termination of the Central Agreement previously defined, and the expected lives of its capital assets. In light of the May 20, 2013 extension of the earliest possible termination date of the Central Agreement from 2030 to 2058, the Authority is in the process of extending the average life of its debt in order to better align its debt amortization to the expected lives of its capital assets. The Authority expects to achieve this alignment through a combination of selling longer dated debt for a portion of the Authority's capital needs and restructuring to extend the maturity of a portion of its existing debt. While the size and scope of this restructuring program will evolve over time, the Authority estimates that it has substantially completed the restructuring portion of the program by refinancing and extending approximately $600.0 million of its existing debt.

The Authority currently estimates the total construction budget associated with a 45% ownership interest in the Summer Nuclear Units 2 and 3 to be approximately $5.1 billion including approximately $168.0 million for transmission and approximately $138.0 million for the initial fuel core and the remaining $4.8 billion for construction of the units. The Authority intends to fund the remaining construction with the proceeds of additional bond sales projected in calendar years 2015 through 2018 and proceeds from the sale of a 5% project ownership interest to SCE&G. While the Authority expects to fund the remaining construction of Summer Nuclear Units 2 and 3 with Revenue Obligations and commercial paper, it also has a pending application with the Department of Energy (DOE) for a loan guarantee to fund construction should it be beneficial to do so.

Liquidity and Capital Resources

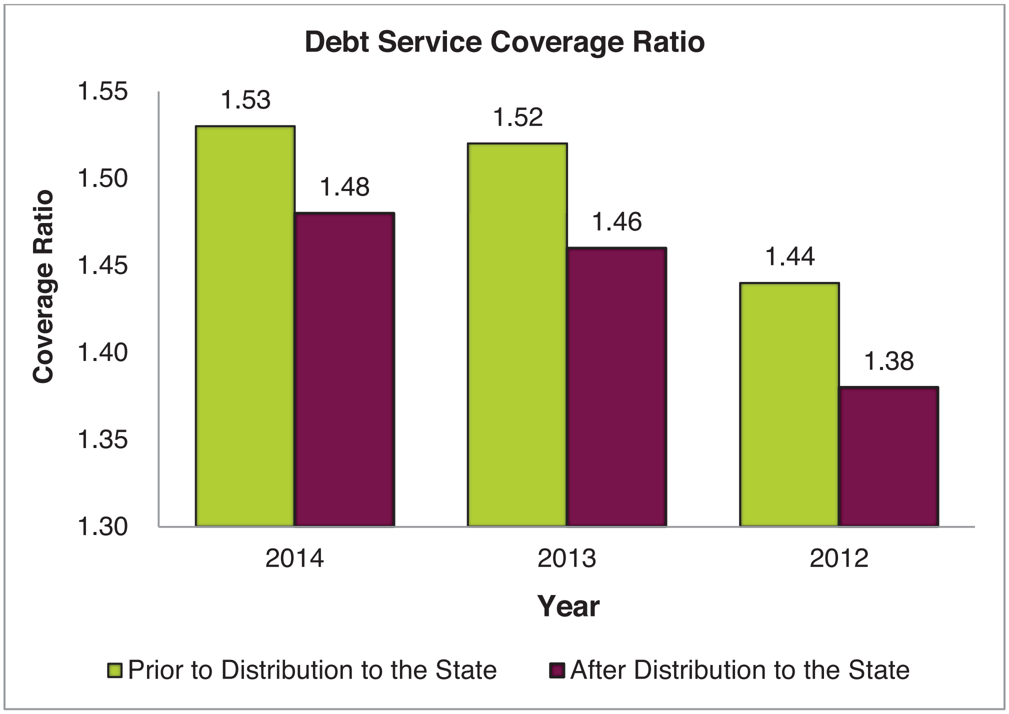
Santee Cooper has significant cash flow from operating activities, access to capital markets, bank facilities and special funds deposit balances.

At December 31, 2014, Santee Cooper had $1.9 billion of cash and investments, of which $692.1 million was available to fund various operating, construction, debt service and contingency requirements. Balances in the decommissioning funds totaled $206.5 million. Revolving credit agreements with banks at December 31, 2014 totaled $800.0 million, and are used to support the issuance of commercial paper. The agreements mature at various dates in 2015 through 2017 and management expects to renew or replace the agreements as needed prior to expiration.

Net cash provided by the Authority during 2014 was $104.6 million. This increase in cash was due to net cash provided by operating activities of $1.0 billion, offset by cash used in financing and investing activities of $877.2 million and $52.8 million, respectively.

DEBT SERVICE COVERAGE

The Authority's debt service coverage (excluding commercial paper and other) for the years ended December 31, 2014, 2013 and 2012 is shown below:



BOND RATINGS

Bond ratings assigned by various agencies for the years ended December 31, 2014, 2013 and 2012 were as follows:

Agency / Lien Level	2014	2013	2012
Fitch Ratings			
Revenue Obligations	**A+**	AA-	AA-
Commercial Paper	**F1**	F1+	F1+
Moody's Investors Service, Inc.			
Revenue Obligations	**A1**	A1	Aa3
Commercial Paper	**P-1**	P-1	P-1
Standard & Poor's Rating Services			
Revenue Obligations	**AA-**	AA-	AA-
Commercial Paper	**A-1**	A-1	A-1
Taxable LIBOR Index Bonds	**SP-1+**	SP-1+	SP-1+

Bond Market Transactions for Years 2014, 2013 and 2012

YEAR 2014

Revenue Obligations:	**2014 Series M1 - Current Interest Bearing Bonds (CIBS)**	**Par Amount:**	$ 32,393,000
Purpose:	To finance a portion of the Authority's ongoing capital program	**Date Closed:**	May 22, 2014
Comments:	Tax-exempt minibonds		

Revenue Obligations:	**2014 Series M1 - Capital Appreciation Bonds (CABS)**	**Par Amount:**	$ 7,191,800
Purpose:	To finance a portion of the Authority's ongoing capital program	**Date Closed:**	May 22, 2014
Comments:	Tax-exempt minibonds		

Revenue Obligations:	**2014 Tax-exempt Series A**	**Par Amount:**	$ 600,000,000
Purpose:	To finance a portion of the Authority's ongoing capital program	**Date Closed:**	July 9, 2014
Comments:	Tax-exempt bonds with an all-in true interest cost of 4.92 percent		

Revenue Obligations:	**2014 Tax-exempt Refunding Series B**	**Par Amount:**	$ 42,275,000
Purpose:	Refund a portion of the following: 2004 Series A	**Date Closed:**	July 9, 2014
Comments:	Tax-exempt bonds with an all-in true interest cost of 4.41 percent		

Revenue Obligations:	**2014 Tax-Exempt Refunding Series C and Taxable Refunding Series D**	**Par Amount:**	$ 736,320,000
Purpose:	Refund a portion of the following: 2003 Refunding Series A, 2005 Refunding Series A, 2006 Series A, 2006 Refunding Series C, 2007 Series A, 2007 Refunding Series B, 2008 Series A, 2009 Series B, 2010 Refunding Series B, 2011 Refunding Series B, 2012 Refunding Series A, 2012 Refunding Series B, 2012 Refunding Series C, 2012 Series D, and 2013 Taxable Series D London Interbank Offered Rate Index (LIBOR Index)	**Date Closed:**	October 28, 2014
Comments:	Tax-exempt and taxable bonds with an all-in true interest cost of 3.78 percent		

YEAR 2013

Revenue Obligations:	2013 Series M1 - Current Interest Bearing Bonds (CIBS)	Par Amount:	$ 18,219,000
Purpose:	To finance a portion of the Authority's ongoing capital program	Date Closed:	May 23, 2013
Comments:	Tax-exempt minibonds		

Revenue Obligations:	2013 Series M1 - Capital Appreciation Bonds (CABS)	Par Amount:	$ 5,035,800
Purpose:	To finance a portion of the Authority's ongoing capital program	Date Closed:	May 23, 2013
Comments:	Tax-exempt minibonds		

Revenue Obligations:	2013 Tax-exempt Series A	Par Amount:	$ 252,655,000
Purpose:	To finance a portion of the Authority's ongoing capital program	Date Closed:	August 21, 2013
Comments:	Tax-exempt bonds with an all-in true interest cost of 5.32 percent		

Revenue Obligations:	2013 Tax-exempt Refunding Series B	Par Amount:	$ 388,730,000
Purpose:	Refund a portion of the following: 2003 Refunding Series A, 2004 Series A, 2006 Series A, 2007 Series A, 2008 Taxable Series B, 2009 Series B, 2011 Taxable Series A (LIBOR Index) and 2012 Series D	Date Closed:	August 21, 2013
Comments:	Tax-exempt bonds with an all-in true interest cost of 5.32 percent		

Revenue Obligations:	2013 Taxable Series C	Par Amount:	$ 250,000,000
Purpose:	Refund a portion of the following: 2003 Refunding Series A and 2008 Taxable Series B	Date Closed:	August 21, 2013
Comments:	Taxable bonds with an all-in true interest cost of 5.83 percent		

Revenue Obligations:	2013 Taxable Series D (LIBOR Index Bonds)	Par Amount:	$ 450,000,000
Purpose:	Refund a portion of the following: 2008 Taxable Series B, 2011 Taxable Series A (LIBOR Index) and 2012 Refunding Series C	Date Closed:	August 21, 2013
Comments:	Taxable bonds with variable interest rate set monthly based on the London Interbank Offered Rate (LIBOR) plus 87.5 - 110.0 basis points		

Revenue Obligations:	2013 Tax-exempt Series E	Par Amount:	$ 506,765,000
Purpose:	To finance a portion of the Authority's ongoing capital program	Date Closed:	October 4, 2013
Comments:	Tax-exempt bonds with an all-in true interest cost of 5.34 percent		

Bond Market Transactions for Years 2014, 2013 and 2012 (continued)

YEAR 2012

Revenue Obligations:	2012 Refunding Series A	Par Amount:	$ 99,405,000
Purpose:	Refund a portion of the following: 2003 Refunding Series A and 2004 Series A	Date Closed:	February 9, 2012
Comments:	Gross savings of $17.3 million over the life of the bonds		
Revenue Obligations:	2012 Refunding Series B	Par Amount:	$ 32,325,000
Purpose:	Refund a portion of the following: 2002 Refunding Series A	Date Closed:	April 5, 2012
Comments:	Gross savings of $8.0 million over the life of the bonds		
Revenue Obligations:	2012 Tax-exempt Series D	Par Amount:	$ 312,160,000
Purpose:	To finance a portion of the tax-exempt construction for Cross Unit 4, Capital Transmission, New Source Review, Nuclear Transmission and Summer Nuclear Units 2 and 3	Date Closed:	April 26, 2012
Comments:	Tax-exempt bonds with an all-in true interest cost of 4.30 percent		
Revenue Obligations:	2012 Taxable Series E	Par Amount:	$ 262,830,000
Purpose:	To finance a portion of the taxable construction for Summer Nuclear Units 2 and 3	Date Closed:	April 26, 2012
Comments:	Taxable bonds with an all-in true interest cost of 4.27 percent		
Revenue Obligations:	2012 Series M1 - Current Interest Bearing Bonds (CIBS)	Par Amount:	$ 17,572,000
Purpose:	To finance a portion of the Authority's ongoing capital program	Date Closed:	May 17, 2012
Comments:	Tax-exempt minibonds		
Revenue Obligations:	2012 Series M1 - Capital Appreciation Bonds (CABS)	Par Amount:	$ 3,565,800
Purpose:	To finance a portion of the Authority's ongoing capital program	Date Closed:	May 17, 2012
Comments:	Tax-exempt minibonds		
Revenue Obligations:	2012 Refunding Series C	Par Amount:	$ 119,145,000
Purpose:	Refund a portion of the following: 2002 Refunding Series D	Date Closed:	October 9, 2012
Comments:	Gross savings of $20.0 million over the life of the bonds		
Revenue Obligations:	2012 Series M2 - Current Interest Bearing Bonds (CIBS)	Par Amount:	$ 14,683,500
Purpose:	To finance a portion of the Authority's ongoing capital program	Date Closed:	November 20, 2012
Comments:	Tax-exempt minibonds		
Revenue Obligations:	2012 Series M2 - Capital Appreciation Bonds (CABS)	Par Amount:	$ 3,504,400
Purpose:	To finance a portion of the Authority's ongoing capital program	Date Closed:	November 20, 2012
Comments:	Tax-exempt minibonds		

Cherry Bekaert LLP
CPAs & Advisors

Report of Independent Auditor

The Advisory Board and Board of Directors
South Carolina Public Service Authority
Moncks Corner, South Carolina

Report on the Financial Statements

We have audited the accompanying combined financial statements of the South Carolina Public Service Authority (the "Authority") (a component unit of the state of South Carolina), which comprise the combined statements of net position as of December 31, 2014 and 2013, and the related combined statements of revenues, expenses, and changes in net position and cash flows for the years then ended, and the related notes to the combined financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of the combined financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of combined financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express opinions on these combined financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America and the standards applicable to financial audits contained in *Government Audit Standards*, issued by the Comptroller General of the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the combined financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the combined financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the combined financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the Authority's preparation and fair presentation of the combined financial statements in order to design audit procedures that are appropriate in the circumstances but not for the purpose of expressing an opinion on the effectiveness of the Authority's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the combined financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinions.

Opinions

In our opinion, the combined financial statements referred to above present fairly, in all material respects, the respective financial position of the Authority as of December 31, 2014 and 2013, and results of its operations and its cash flow for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Other Matters

Emphasis of Matter
As discussed in Note 1C to the combined financial statements, the Authority reclassified certain amounts that were previously reported in the Combined Statements of Net Position and Cash Flows for the year ended December 31, 2013. Our opinion is not modified with respect to this matter.

Required Supplementary Information
Accounting principles generally accepted in the United States of America require that the Management's Discussion and Analysis be presented to supplement the combined financial statements. Such information, although not a part of the combined financial statements, is required by the Governmental Accounting Standards Board who considers it to be an essential part of financial reporting for placing the combined financial statements in an appropriate operational, economic, or historical context. We have applied certain limited procedures to the required supplementary information in accordance with auditing standards generally accepted in the United States of America, which consisted of inquiries of management about the methods of preparing the information and comparing the information for consistency with management's responses to our inquiries, the combined financial statements, and other knowledge we obtained during our audit of the combined financial statements. We do not express an opinion or provide any assurance on the information because the limited procedures do not provide us with sufficient evidence to express an opinion or provide any assurance.

Other Information
Our audit was conducted for the purpose of forming opinions on the combined financial statements as a whole. The Chairman and CEO Letter, Corporate Statistics, Audit Committee Chairwoman's Letter, Leadership, and Office Locations as listed in the table of contents of the annual report are presented for purposes of additional analysis and are not a required part of the combined financial statements. Such information has not been subjected to the auditing procedures applied in our audits of the combined financial statements, and accordingly, we do not express an opinion on them.

Other Reporting Required by Government Auditing Standards
In accordance with Government Auditing Standards, we have also issued our report dated February 19, 2015, on our consideration of the Authority's internal control over financial reporting and on our tests of its compliance with certain provisions of laws, regulations, contracts and grant agreements and other matters. The purpose of that report is to describe the scope of our testing of internal control over financial reporting and compliance and the results of that testing and not to provide an opinion on the internal control over financial reporting or on compliance. That report is an integral part of an audit performed in accordance with Government Auditing Standards, and should be considered in assessing the Authority's internal control over financial reporting and compliance.

Cherry Bekaert LLP

Raleigh, North Carolina
February 19, 2015

Combined Statements of Net Position

South Carolina Public Service Authority
As of December 31, 2014 and 2013

	2014	2013
	(Thousands)	
ASSETS		
Current assets		
Unrestricted cash and cash equivalents	$ 171,830	$ 172,738
Unrestricted investments	520,282	526,584
Restricted cash and cash equivalents	289,149	182,455
Restricted investments	836,032	762,650
Receivables, net of allowance for doubtful accounts of $1,555 and $1,315 at December 31, 2014 and 2013, respectively	187,324	189,092
Materials inventory	113,635	113,865
Fuel inventory		
Fossil fuels	333,648	446,998
Nuclear fuel-net	150,577	163,147
Interest receivable	1,786	2,664
Prepaid expenses and other current assets	233,639	248,520
Total current assets	2,837,902	2,808,713
Noncurrent assets		
Restricted cash and cash equivalents	352	1,535
Restricted investments	122,657	109,060
Capital assets		
Utility plant	7,023,729	6,910,962
Long lived assets-asset retirement cost	507,394	507,394
Accumulated depreciation	(3,332,127)	(3,150,020)
Total utility plant-net	4,198,996	4,268,336
Construction work in progress	2,712,851	2,100,631
Other physical property-net	5,939	6,084
Investment in associated companies	8,584	6,840
Unamortized debt expenses	35,902	36,473
Costs to be recovered from future revenue	247,359	227,561
Regulatory asset-asset retirement obligation	660,181	603,663
Other noncurrent and regulatory assets	173,870	399,465
Total noncurrent assets	8,166,691	7,759,648
Total assets	$ 11,004,593	$ 10,568,361
DEFERRED OUTFLOWS OF RESOURCES		
Accumulated decrease in fair value of hedging derivatives	$ 69,958	$ 19,367
Unamortized loss on refunded and defeased debt	133,680	119,868
Total deferred outflows of resources	$ 203,638	$ 139,235
Total assets & deferred outflows of resources	$ 11,208,231	$ 10,707,596

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

Combined Statements of Net Position *(continued)*

South Carolina Public Service Authority
As of December 31, 2014 and 2013

		2014		2013
		(Thousands)		
LIABILITIES				
Current liabilities				
Current portion of long-term debt	**$**	**149,689**	$	133,671
Accrued interest on long-term debt		**79,061**		100,159
Commercial paper		**410,139**		372,073
Accounts payable		**260,727**		216,163
Other current liabilities		**131,766**		69,978
Total current liabilities		**1,031,382**		892,044
Noncurrent liabilities				
Construction liabilities		**6,377**		3,616
Asset retirement obligation liability		**1,043,629**		1,024,253
Total long-term debt (net of current portion)		**6,399,449**		6,313,821
Unamortized debt discounts and premiums		**239,713**		142,558
Long-term debt-net		**6,639,162**		6,456,379
Other credits and noncurrent liabilities		**110,717**		97,182
Total noncurrent liabilities		**7,799,885**		7,581,430
Total liabilities	**$**	**8,831,267**	$	8,473,474
DEFERRED INFLOWS OF RESOURCES				
Accumulated increase in fair value of hedging derivatives	**$**	**1,138**	$	8,146
Nuclear decommissioning costs		**207,363**		185,849
Total deferred inflows of resources	**$**	**208,501**	$	193,995
NET POSITION				
Net invested in capital assets	**$**	**957,835**	$	895,969
Restricted for debt service		**108,457**		92,662
Restricted for capital projects		**6,515**		0
Unrestricted		**1,095,656**		1,051,496
Total net position	**$**	**2,168,463**	$	2,040,127
Total liabilities, deferred inflows of resources & net position	**$**	**11,208,231**	$	10,707,596

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Combined Statements of Revenues, Expenses and Changes in Net Position

South Carolina Public Service Authority
Years Ended December 31, 2014 and 2013

	2014	2013
	(Thousands)	
Operating revenues		
Sale of electricity	$ 1,975,362	$ 1,796,230
Sale of water	7,854	7,282
Other operating revenue	14,131	13,064
Total operating revenues	1,997,347	1,816,576
Operating expenses		
Electric operating expenses		
Production	109,194	104,740
Fuel	820,720	741,255
Purchased and interchanged power	237,187	217,311
Transmission	24,885	24,555
Distribution	10,626	10,727
Customer accounts	15,616	15,656
Sales	12,378	6,016
Administrative and general	89,286	91,792
Electric maintenance expenses	116,560	106,463
Water operating expenses	2,687	2,502
Water maintenance expenses	858	890
Total operating and maintenance expenses	1,439,997	1,321,907
Depreciation	173,743	196,812
Sums in lieu of taxes	5,484	5,463
Total operating expenses	1,619,224	1,524,182
Operating income	378,123	292,394
Nonoperating revenues (expenses)		
Interest and investment revenue	29,023	3,945
Net decrease in the fair value of investments	(2,017)	(2,320)
Interest expense on long-term debt	(268,989)	(221,067)
Interest expense on commercial paper and other	(4,840)	(4,063)
Amortization expense	(1,164)	4,352
Costs to be recovered from future revenue	19,798	7,396
U.S. Treasury subsidy on Build America Bonds	7,542	7,486
Other-net	(8,481)	(2,185)
Total nonoperating revenues (expenses)	(229,128)	(206,456)
Income before transfers	148,995	85,938
Capital contributions & transfers		
Distribution to the State	(20,659)	(20,394)
Total capital contributions & transfers	(20,659)	(20,394)
Change in net position	128,336	65,544
Total net position-beginning	2,040,127	1,974,583
Total net position-ending	$ 2,168,463	$ 2,040,127

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

Combined Statements of Cash Flows

South Carolina Public Service Authority
Years Ended December 31, 2014 and 2013

	2014	2013
	(Thousands)	
Cash flows from operating activities		
Receipts from customers	$ 1,998,875	$ 1,832,536
Payments to non-fuel suppliers	(124,575)	(277,732)
Payments for fuel	(813,871)	(736,022)
Purchased power	(237,263)	(217,386)
Payments to employees	(162,872)	(158,002)
Other receipts-net	374,315	301,072
Net cash provided by operating activities	1,034,609	744,466
Cash flows from non-capital related financing activities		
Distribution to the State	(20,659)	(20,394)
Proceeds from sale of bonds	54,105	316,427
Proceeds from issuance of commercial paper notes	229,105	169,450
Repayment of commercial paper notes	(105,062)	(191,476)
Refunding / defeasance of long-term debt	(469,708)	(348,481)
Repayment of long-term debt	(143)	(13)
Interest paid on long-term debt	(18,156)	(22,037)
Interest paid on commercial paper and other	(3,286)	(4,320)
Bond issuance and other related costs	(7,424)	(2,941)
Net cash used in non-capital related financing activities	(341,228)	(103,785)
Cash flows from capital-related financing activities		
Proceeds from sale of bonds	1,364,075	1,549,947
Proceeds from issuance of commercial paper notes	59,661	115,447
Repayment of commercial paper notes	(145,638)	(50,631)
Refunding / defeasance of long-term debt	(753,782)	(508,140)
Repayment of long-term debt	(95,615)	(167,399)
Interest paid on long-term debt	(304,308)	(257,111)
Interest paid on commercial paper and other	(2,331)	(1,663)
Construction and betterments of utility plant	(725,145)	(743,819)
Bond issuance and other related costs	75,525	(31,276)
Other-net	(8,427)	(60,487)
Net cash used in capital-related financing activities	(535,985)	(155,132)
Cash flows from investing activities		
Net (decrease) in investments	(82,694)	(610,834)
Interest on investments	29,901	2,969
Net cash used in investing activities	(52,793)	(607,865)
Net increase/(decrease) in cash and cash equivalents	104,603	(122,316)
Cash and cash equivalents-beginning	356,728	479,044
Cash and cash equivalents-ending	$ 461,331	$ 356,728

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

Combined Statements of Cash Flows *(continued)*

South Carolina Public Service Authority
Years Ended December 31, 2014 and 2013

	2014	2013
	(Thousands)	
Reconciliation of operating income to net cash provided by operating activities		
Operating income	**$ 378,123**	$ 292,394
Adjustments to reconcile operating income to net cash provided by operating activities		
Depreciation	**173,743**	196,812
Amortization of nuclear fuel	**22,552**	28,500
Net power gains involving associated companies	**(27,711)**	(25,243)
Distributions from associated companies	**23,674**	22,444
Advances to associated companies	**(107)**	(4)
Other income and expenses	**3,807**	12,895
Changes in assets and liabilities		
Accounts receivable-net	**1,768**	15,942
Inventories	**113,581**	28,877
Prepaid expenses	**(21,928)**	23,491
Other deferred debits	**245,692**	73,245
Accounts payable	**50,545**	71,006
Other current liabilities	**57,779**	319
Other noncurrent liabilities	**13,091**	3,788
Net cash provided by operating activities	**$ 1,034,609**	$ 744,466

	2014	2013
Composition of cash and cash equivalents		
Current		
Unrestricted cash and cash equivalents	**$ 171,830**	$ 172,738
Restricted cash and cash equivalents	**289,149**	182,455
Noncurrent		
Restricted cash and cash equivalents	**352**	1,535
Cash and cash equivalents at the end of the year	**$ 461,331**	$ 356,728

NOTES

NOTE 1 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A - Reporting Entity - The South Carolina Public Service Authority (the Authority or Santee Cooper), a component unit of the State of South Carolina (the State), was created in 1934 by the State legislature. The Santee Cooper Board of Directors (Board) is appointed by the Governor of South Carolina with the advice and consent of the Senate. The purpose of the Authority is to provide electric power and wholesale water to the people of South Carolina. Capital projects are funded by bonds, commercial paper and internally generated funds. As authorized by State law, the Board sets rates charged to customers to pay debt service and operating expenses and to provide funds required under bond covenants.

B - System of Accounts - The accounting records of the Authority are maintained on an accrual basis in accordance with accounting principles generally accepted in the United States (GAAP) issued by the Governmental Accounting Standards Board (GASB) applicable to governmental entities that use proprietary fund accounting and the Financial Accounting Standards Board (FASB) that do not conflict with rules issued by the GASB.

The Authority's combined financial statements include the accounts of the Lake Moultrie and Lake Marion Regional Water Systems after elimination of inter-company accounts and transactions. The accounts are maintained substantially in accordance with the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission (FERC) for the electric system and the National Association of Regulatory Utility Commissioners (NARUC) for the water systems.

The Authority also complies with policies and practices prescribed by its Board and practices common in both industries. As the Board is authorized to set rates, the Authority follows GASB 62. This standard provides for the reporting of assets and liabilities consistent with the economic effect of the rate structure.

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions in the Authority's reporting. This practice affects the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results may differ from those estimates.

C – Reclassifications - To achieve conformity and comparability, the Authority may reclassify certain amounts in prior year financial statements where applicable.

During 2014, the Authority determined that the Net Position section of the Combined Statements of Net Position should be reclassified. As of December 31, 2013 the Net invested in capital assets category was understated by $2.6 million and Unrestricted was overstated by $2.6 million. The reclassification is a result of certain items being reassessed as capital related or non-capital related.

For comparative purposes, certain portions of the Combined Statement of Cash Flows have been reclassified for the year ended December 31, 2013. This is due to a reassessment of the nature of transactions in the capital related financing category that were deemed to be non-capital or operating. Accordingly, for the year ended December 31, 2013, $69.7 million has been reclassified out of capital related financing activities to non-capital and operating.

D - Current and Noncurrent - The Authority presents assets and liabilities in order of relative liquidity. The liquidity of an asset is determined by how readily it is expected to be converted to cash and whether restrictions limit the use of the resources. The liquidity of a liability is based on its maturity, or when cash is expected to be used to liquidate the liability.

E - Restricted Assets - For purposes of the Combined Statements of Net Position and Combined Statements of Cash Flows, assets are restricted when constraints are placed on their use by either:

(1) External creditors, grantors, contributors, or laws or regulations of other governments; or
(2) Law through constitutional provisions or enabling legislation.

Assets not meeting the requirements of restricted are classified as unrestricted.

F - Cash and Cash Equivalents - For purposes of the Combined Statements of Net Position and Combined Statements of Cash Flows, the Authority considers highly liquid investments with original maturities of ninety days or less and cash on deposit with financial institutions as unrestricted and restricted cash and cash equivalents.

G - Inventory - Material and fuel inventories are carried at weighted average costs. At the time of issuance or consumption, an expense is recorded at the weighted average cost.

H - Utility Plant - Utility plant is recorded at cost, which includes materials, labor, overhead and interest capitalized during construction. Interest is capitalized only when interest payments are funded through borrowings. The Authority capitalized $59.3 and $83.7 million of interest in 2014 and 2013, respectively. Other interest expense is recovered currently through rates. The costs of maintenance, repairs and minor replacements are charged to appropriate operation and maintenance expense accounts. The costs of renewals and betterments are capitalized. The original cost of utility plant retired and the cost of removal, less salvage, are charged to accumulated depreciation.

I - Depreciation - Depreciation is computed using composite rates on a straight-line basis over the estimated useful lives of the various classes of the plant. Composite rates are applied to the gross plant balance of various classes of assets which includes appropriate adjustments for cost of removal and salvage. The Authority periodically has depreciation studies performed by independent parties to assist management in establishing appropriate composite depreciation rates. For assets not grouped in a plant class, straight-line depreciation is used over the estimated useful life of the asset.

Annual depreciation provisions, expressed as a percentage of average depreciable utility plant in service, were as follows:

Years Ended December 31,	**2014**	2013
Annual average depreciation percentages	**2.6%**	2.9%

Note: Depreciation expense includes amortization of property under capitalized leases.

J - Retirement of Long Lived Assets - The Authority follows the guidance of FASB ASC 410 in regards to the decommissioning of V.C. Summer Nuclear Station (Summer Nuclear) and closing coal-fired generation ash ponds. The requirements for both were recorded within capital assets on the accompanying Combined Statements of Net Position.

The asset retirement obligation (ARO) is adjusted each period for any liabilities incurred or settled during the period, accretion expense and any revisions made to the estimated cash flows. The following table summarizes the Authority's transactions:

Years Ended December 31,		**2014**			2013	
	Nuclear	**Ash Ponds**	**Total**	Nuclear	Ash Ponds	Total
			(Millions)			
Reconciliation of ARO Liability:						
Balance as of January 1,	**$ 664.4**	**$ 359.8**	**$ 1,024.2**	$ 650.3	$ 352.0	$ 1,002.3
Accretion expense	**14.4**	**5.0**	**19.4**	14.1	7.8	21.9
Balance as of December 31,	**$ 678.8**	**$ 364.8**	**$ 1,043.6**	$ 664.4	$ 359.8	$ 1,024.2
Asset Retirement Cost (ARC):	**$ 334.3**	**$ 173.1**	**$ 507.4**	$ 334.3	$ 173.1	$ 507.4

K - Reporting Impairment Losses - The Authority's Board authorized the retirement of six generating units during 2012. December 2012 was set for the permanent retirement date for four coal-fired generating units (Grainger Units 1 and 2 and Jefferies Units 3 and 4). In compliance with GASB 42, the required accounting entries were recorded for capital assets, depreciation effect, costs to be recovered from future revenue (CTBR) expense, materials and supplies.

2014 updates include continued preparation for a future sale of Grainger Units 1 and 2 and Jefferies Units 3 and 4 generating station assets. In addition, sales of coal (fuel stock pile) from the Jefferies and Grainger generating stations also continued. The sale of coal will continue at both generation sites (Jefferies and Grainger) until fully depleted.

The Authority continues to implement the appropriate processes to fully close the retired units in order to remain in compliance with regulatory requirements. It should be noted that the closure of the ash ponds at each site will result in additional entries and adjustments to accumulated depreciation, ARO and various other balances in subsequent years.

L - Investment in Associated Companies - The Authority is a member of The Energy Authority (TEA). Approximate ownership interests were as follows:

Years Ended December 31,	2014	2013
Owners	Ownership (%)	
City Utilities of Springfield (Missouri)	**5.0**	6.7
Cowlitz Public Utility District (Washington)	**5.0**	6.7
Gainesville Regional Utilities (Florida)	**5.0**	6.6
American Municipal Power (Ohio)	**17.0**	0.0
JEA (Florida)	**17.0**	20.0
MEAG Power (Georgia)	**17.0**	20.0
Nebraska Public Power District (Nebraska)	**17.0**	20.0
Santee Cooper (South Carolina)	**17.0**	20.0
Total	**100.0**	100.0

TEA markets wholesale power and coordinates the operation of the generation assets of its members to maximize the efficient use of electrical energy resources, reduce operating costs and increase operating revenues of the members. It is expected to accomplish the foregoing without impacting the safety and reliability of the electric system of each member. TEA does not engage in the construction or ownership of generation or transmission assets. In addition, it assists members with fuel hedging activities and acts as an agent in the execution of forward transactions. The Authority accounts for its investment in TEA under the equity method of accounting.

All of TEA's revenues and costs are allocated to the members. The following table summarizes the transactions applicable to the Authority:

Years Ended December 31,	2014	2013
	(Thousands)	
TEA Investment:		
Balance as of January 1,	**$ 6,644**	$ 7,932
Reduction to power costs and increases in electric revenues	**25,336**	21,322
Less: Distributions from TEA	**23,674**	22,444
Less: Other (includes equity losses)	**25**	166
Balance as of December 31,	**$ 8,281**	$ 6,644
Due To/Due From TEA:		
Payable to	**$ 26,125**	$ 29,249
Receivable from	**$ 782**	$ 1,592

The Authority's exposure relating to TEA is limited to the Authority's capital investment, any accounts receivable and trade guarantees provided by the Authority. These guarantees are within the scope of FASB ASC 952. Upon the Authority making any payments under its electric guarantee, it has certain contribution rights with the other members in order that payments made under the TEA member guarantees would be equalized ratably, based upon each member's equity ownership interest. After such contributions have been affected, the Authority would only have recourse against TEA to recover amounts paid under the guarantee. The term of this guarantee is generally indefinite, but the Authority has the ability to terminate its guarantee obligations by providing advance notice to the beneficiaries thereof. Such termination of its guarantee obligations only applies to TEA transactions not yet entered into at the time the termination takes effect. The Authority's support of TEA's trading activities is limited based on the formula derived from the forward value of TEA's trading positions at a point in time. The formula was approved by the Authority's Board. At December 31, 2014, the trade guarantees are an amount not to exceed approximately $85.3 million.

The Authority is also a member of Colectric Partners (Colectric). Ownership interests were as follows:

Years Ended December 31,	2014	2013
Owners	Ownership (%)	
JEA (Florida)	**25.0**	25.0
MEAG Power (Georgia)	**25.0**	25.0
Nebraska Public Power District (Nebraska)	**25.0**	25.0
Santee Cooper (South Carolina)	**25.0**	25.0
Total	**100.0**	100.0

Colectric provides public power utilities with key project and business management resources. Colectric also specializes in the development, project management, operations and maintenance of public power utilities' electric generation facilities and electric system infrastructure. The members may elect to participate in Colectric initiatives based on individual utility needs.

Currently, the Authority participates in several of Colectric's initiatives. One involves managing the major gas turbine overhauls, thereby promoting the sharing of spare parts and technical expertise. Another is a strategic sourcing initiative, intended to achieve major cost savings through volume purchasing leverage. Other initiatives in which the Authority participates include steam turbine (combined cycle and non-combined cycle), gas turbine inlet air filters, maintenance/inspection/repair and borescope/NDT services for steam and gas turbines.

The Authority's exposure relating to Colectric is limited to its capital investment, any accounts receivable and any indemnifications related to agreements between Colectric and the Authority. These indemnifications are within the scope of FASB ASC 952. The Authority's initial investment in Colectric was $413,000. The balance in its member equity account at December 31, 2014 and 2013 was approximately $194,000 and $196,000, respectively. Since 2001, cumulative net direct cost and direct savings have been $4.4 million and $18.8 million, respectively. Due to the maintenance sharing initiative ceasing, the Colectric Board of Directors voted to cease operations of Colectric effective March 31, 2015.

On October 1, 2013, the Authority along with MEAG Power became originating members of TEA Solutions. JEA and Cowlitz Public Utility District joined later in 2013. TEA Solutions is a publicly supported non-profit corporation. Members and ownership interests were as follows:

Years Ended December 31,	2014	2013
Owners	Ownership (%)	
Cowlitz Public Service District (Washington)	**8.0**	0.0
American Municipal Power (Ohio)	**23.0**	10.0
JEA (Florida)	**23.0**	30.0
MEAG Power (Georgia)	**23.0**	30.0
Santee Cooper (South Carolina)	**23.0**	30.0
Total	**100.0**	100.0

TEA Solutions was formed mainly to (1) coordinate the operation of electric generation resources and the purchase and sale of electric power on behalf of the corporation's clients; (2) coordinate the purchase and sale of natural gas relating to fuel for clients' generation of electric energy or relating to clients' operation of a retail gas distribution system; and (3) provide consulting and software services to clients.

The Authority funded its initial share of TEA Solutions with a $150,000 contribution in 2013. This contribution was to cover legal, consulting and other start-up costs pertaining to TEA Solutions. The Authority's exposure relating to TEA Solutions is limited to the Authority's capital investment, any accounts receivable and trade guarantees provided by the Authority. The balance in its member equity account at December 31, 2014 and 2013 was approximately $110,000 and $144,000, respectively.

M – Deferred Outflows / Deferred Inflows of Resources - In addition to assets, the Combined Statements of Net Position reports a separate section for Deferred Outflow of Resources. These items represent a consumption of net position that applies to a future period and until that time will not be recognized as an expense or expenditure. The Authority has two items meeting this criterion: (1) accumulated decrease in fair value of hedging derivatives; and (2) unamortized loss on refunded and defeased debt.

In addition to liabilities, the Combined Statements of Net Position also reports a separate section for Deferred Inflows of Resources. These items represent an acquisition of net position that applies to a future period and until that time will not be recognized as revenue. The Authority has two items meeting this criterion: (1) accumulated increase in fair value of hedging derivatives; and (2) nuclear decommissioning costs.

The following table summarizes the Authority's total deferred items:

Years Ended December 31,		**2014**		2013
		(Thousands)		
Deferred outflows of resources	**$**	**203,638**	$	139,235
Deferred inflows of resources	**$**	**208,501**	$	193,995

N - Accounting for Derivative Instruments - In compliance with GASB 53 and 64, the annual changes in the fair value of effective hedging derivative instruments are required to be deferred (reported as deferred outflows of resources and deferred inflows of resources on the Combined Statements of Net Position). Deferral of changes in fair value generally lasts until the transaction involving the hedged item ends.

Natural gas and heating oil, core business commodity inputs for the Authority, have historically been hedged in an effort to mitigate gas and oil cost risk by reducing cost volatility and improving cost effectiveness. Unrealized gains and losses related to such activity are deferred in a regulatory account and recognized in earnings as fuel costs are incurred in the production cycle.

A summary of the Authority's derivative activity for years ended December 31, 2014 and 2013 is below:

Cash Flow Hedges and Summary of Activity

Years Ended December 31,			**2014**		2013
	Account Classification		(Millions)		
Fair Value					
Natural gas	Regulatory assets/liabilities	**$**	**(60.3)**	$	(11.5)
Heating oil	Regulatory assets/liabilities		**(8.6)**		0.2
Changes in Fair Value					
Natural gas	Regulatory assets/liabilities	**$**	**(48.8)**	$	20.3
Heating oil	Regulatory assets/liabilities		**(8.8)**		(0.1)
Recognized Net Gains (Losses)					
Natural gas	Operating expense-fuel	**$**	**5.8**	$	(21.2)
Heating oil	Operating expense-fuel		**(0.4)**		(0.2)
Realized But Not Recognized Net Gains (Losses)					
Natural gas	Regulatory assets/liabilities	**$**	**2.7**	$	6.5
Heating oil	Regulatory assets/liabilities		**0.0**		(0.2)
Notional					
			MBTUs		
Natural gas			**61,980**		51,860
			Gallons (000s)		
Heating oil			**12,012**		4,620

O - Revenue Recognition and Fuel Costs - Substantially all wholesale and industrial revenues are billed and recorded at the end of each month. Revenues for electricity delivered to retail customers but not billed are accrued monthly. Accrued revenue for retail customers totaled $15.3 million in 2014 and $14.4 million in 2013.

Fuel costs are reflected in operating expenses as fuel is consumed. Fuel expense for all customers is billed utilizing rates and contracts, the majority of which include fuel adjustment provisions based on either the accrued costs for the previous month or the actual weighted average costs for the previous three-month period.

P - Bond Issuance Costs and Refunding Activity - GASB 62 requires that any gains or losses resulting from extinguishment of debt be expensed at the time of extinguishment. GASB 65 requires that debt issuance costs be expensed in the period incurred. In order to align the impact of these pronouncements with the Authority's rate making process, in October 2012, the Board authorized the use of regulatory accounting to allow continuation of prior accounting treatment with regard to these costs.

Consistent with prior accounting periods, unamortized debt discounts, premiums and expenses are amortized to income over the terms of the related debt issues. Gains or losses on refunded and extinguished debt are amortized to earnings over the shorter of the remaining life of the refunded debt or the life of the new debt.

Q - Distribution to the State - Any and all net earnings of the Authority not necessary for the prudent conduct and operation of its business in the best interests of the Authority or to pay the principal of and interest on its bonds, notes, or other evidences of indebtedness or other obligations, or to fulfill the terms and provisions of any agreements made with the purchasers or holders thereof or others must be paid over semiannually to the State Treasurer for the general funds of the State. Nothing in this section shall prohibit the Authority from paying to the State each year up to one percent of its projected operating revenues, as such revenues would be determined on an accrual basis, from the combined electric and water systems. (Code of Laws of South Carolina, as amended Section 58-31-110).

Distributions made to the State in 2014 and 2013 totaled approximately $20.7 million and $20.4 million, respectively.

R - New Accounting Standards

STATEMENT NO. & ISSUE DATE	TITLE/SUMMARY	SUMMARY OF ACTION BY THE AUTHORITY
Statement No. GASB 67	**Financial Reporting for Pension Plans - an amendment of GASB 25**	
Issue Date: June 2012	Effective for Periods Beginning After: June 15, 2013	
Description:	The objective of GASB 67 is to improve financial reporting by state and local governmental pension plans. GASB 67 results from a comprehensive review of the effectiveness of existing standards of accounting and financial reporting for pensions with regard to providing decision-useful information, supporting assessments of accountability and interperiod equity and creating additional transparency. GASB 67 replaces the requirements of Statements No. 25, Financial Reporting for Defined Benefit Pension Plans and Note Disclosures for Defined Contribution Plans and No. 50, Pension Disclosures.	Reviewed and no action required.
Statement No. GASB 68	**Accounting and Financial Reporting for Pensions - an amendment of GASB Statement No. 27**	
Issue Date: June 2012	Effective for Periods Beginning After: June 15, 2014	
Description:	The primary objective of this Statement is to improve accounting and financial reporting by state and local governments for pensions. It also improves information provided by state and local governmental employers about financial support for pensions that is provided by other entities.	Under Review
Statement No. GASB 69	**Government Combinations and Disposals of Government Operations**	
Issue Date: January 2013	Effective for Periods Beginning After: December 15, 2013	
Description:	This statement establishes accounting and financial reporting standards related to government combinations and disposals of government operations. As used in this Statement, the term "government combinations" includes a variety of transactions referred to as mergers, acquisitions and transfers of operations.	Reviewed and no action required.
Statement No. GASB 70	**Accounting and Financial Reporting for Nonexchange Financial Guarantees**	
Issue Date: April 2013	Effective for Periods Beginning After: June 15, 2013	
Description:	The objective of this statement is to improve accounting and financial reporting by state and local governments that extend and receive nonexchange financial guarantees. This Statement requires a government that extends a nonexchange financial guarantee to recognize a liability when qualitative factors and historical data, if any, indicate that it is more likely than not the government will be required to make a payment on the guarantee.	Reviewed and no action required.
Statement No. GASB 71	**Pension Transition for Contributions Made Subsequent to the Measurement Date - an amendment of GASB Statement No. 68**	
Issue Date: November 2013	The provisions of this Statement should be applied simultaneously with the provisions of Statement 68.	
Description:	The objective of this Statement is to address an issue regarding application of the transition provisions of Statement No. 68, "Accounting and Financial Reporting for Pensions." The issue relates to amounts associated with contributions, if any, made by a state of local government employer or nonemployer contributing entity to a defined benefit pension plan after the measurement date of the government's beginning net pension liability.	Under Review

NOTE 2 – COSTS TO BE RECOVERED FROM FUTURE REVENUE

The Authority's rates are established based upon debt service and operating fund requirements. Depreciation is not considered in the cost of service calculation used to design rates. In accordance with GASB 62, the differences between debt principal maturities (adjusted for the effects of premiums, discounts, expenses and amortization of deferred gains and losses) and depreciation on debt financed assets are recognized as CTBR. The recovery of outstanding amounts recorded as CTBR will coincide with the repayment of the applicable outstanding debt. The Authority's summary of CTBR activity is recapped below:

Years Ended December 31,	2014	2013
	(Millions)	
CTBR regulatory asset:		
Balance	**$ 247.4**	$ 227.6
CTBR expense/(reduction to expense):		
Net expense	**$ (19.8)**	$ (7.4)

NOTE 3 – CAPITAL ASSETS

Capital asset activity for the years ended December 31, 2014 and 2013 was as follows:

	Beginning Balances	Increases	Decreases	Ending Balances
		Year 2014 (Thousands)		
Utility plant	**$ 6,910,962**	**$ 156,358**	**$ (43,591)**	**$ 7,023,729**
Long lived assets-asset retirement cost	**507,394**	**0**	**0**	**507,394**
Accumulated depreciation	**(3,150,020)**	**(210,661)**	**28,554**	**(3,332,127)**
Total utility plant - net	**4,268,336**	**(54,303)**	**(15,037)**	**4,198,996**
Construction work in progress	**2,100,631**	**768,586**	**(156,366)**	**2,712,851**
Other physical property - net	**6,084**	**79**	**(224)**	**5,939**
Totals	**$ 6,375,051**	**$ 714,362**	**$ (171,627)**	**$ 6,917,786**
		Year 2013 (Thousands)		
Utility plant	$ 6,744,928	$ 189,268	$ (23,234)	$ 6,910,962
Long lived assets-asset retirement cost	507,394	0	0	507,394
Accumulated depreciation	(2,954,471)	(233,462)	37,913	(3,150,020)
Total utility plant - net	4,297,851	(44,194)	14,679	4,268,336
Construction work in progress	1,643,507	644,343	(187,219)	2,100,631
Other physical property - net	6,560	0	(476)	6,084
Totals	$ 5,947,918	$ 600,149	$ (173,016)	$ 6,375,051

NOTE 4 – CASH AND INVESTMENTS HELD BY TRUSTEE AND FUND DETAILS

All cash and investments of the Authority are held and maintained by custodians and trustees. The use of unexpended proceeds from sale of bonds, debt service funds and other sources is designated in accordance with applicable provisions of various bond resolutions, lease agreements, the Enabling Act included in the South Carolina Code of Laws (the Enabling Act) or by management directive. Restricted funds have constraints placed on their use (see Note 1 - E – "Restricted Assets"). The use of unrestricted funds may be either designated for a specific use by management directive or undesignated, but are available to provide liquidity for operations as needed.

Following are the details of the Authority's funds which are classified in the accompanying financial statements as unrestricted and restricted cash, cash equivalents and investments:

Years Ended December 31,		**2014**			2013	
Funds	**Cash & Cash Equivalents**	**Investments**	**Total**	Cash & Cash Equivalents	Investments	Total
			(Thousands)			
Current Unrestricted:						
Capital Improvement	**$ 44,216**	**$ 132,728**	**$ 176,944**	$ 40,798	$ 85,154	$ 125,952
Debt Reduction	**10,713**	**45,224**	**55,937**	5,201	49,473	54,674
Funds from Taxable Borrowings	**11,457**	**130,895**	**142,352**	10,780	229,403	240,183
General Improvement	**1,438**	**1,450**	**2,888**	413	2,461	2,874
Internal Nuclear Decommissioning Fund	**415**	**83,090**	**83,505**	846	73,595	74,441
Nuclear Fuel	**5,318**	**23,999**	**29,317**	1,010	1,000	2,010
Revenue and Operating	**72,021**	**33,007**	**105,028**	89,103	31,999	121,102
Special Reserve and Other	**26,252**	**69,889**	**96,141**	24,587	53,499	78,086
Total	**$ 171,830**	**$ 520,282**	**$ 692,112**	$ 172,738	$ 526,584	$ 699,322
Current Restricted:						
Debt Service Funds	**$ 65,178**	**$ 122,340**	**$ 187,518**	$ 74,551	$ 118,270	$ 192,821
Funds from Tax-exempt Borrowings	**164,567**	**691,392**	**855,959**	89,250	622,466	711,716
Other	**59,404**	**22,300**	**81,704**	18,654	21,914	40,568
Total	**$ 289,149**	**$ 836,032**	**$ 1,125,181**	$ 182,455	$ 762,650	$ 945,105
Noncurrent Restricted:						
External Nuclear Decommissioning Trust	**$ 352**	**$ 122,657**	**$ 123,009**	$ 1,535	$ 109,060	$ 110,595
Total	**$ 352**	**$ 122,657**	**$ 123,009**	$ 1,535	$ 109,060	$ 110,595
TOTAL FUNDS	**$ 461,331**	**$ 1,478,971**	**$ 1,940,302**	$ 356,728	$ 1,398,294	$ 1,755,022

Cash and investments as of December 31, consisted of the following:		
Cash/Deposits	**$ 87,503**	$ 60,394
Investments	**1,852,799**	1,694,628
Total cash and investments	**$ 1,940,302**	$ 1,755,022

Current Unrestricted Funds – These funds are used for operating activities for the Authority's respective systems. Although funds are segregated per management directive based on their intended use, since no restrictions apply, the funds are available to provide additional liquidity for operations. Included in this category is the internal Nuclear Decommissioning Fund intended by management to be used to offset future nuclear decommissioning costs and represents amounts in excess of the mandated Nuclear Regulatory Commission (NRC) decommissioning requirement which is funded separately in an external Nuclear Decommissioning Trust. Also included are funds from taxable borrowings intended to be used for both capital construction costs and for working capital purposes, as expected at the time proceeds are borrowed.

Current Restricted Funds – These funds are restricted in their allowed use. Debt service funds are restricted for payment of principal and interest debt service on outstanding debt. Funds from tax-exempt borrowings are intended to be used for capital construction costs as expected at the time proceeds are borrowed and are restricted pursuant to sections of both the U.S. Treasury Regulations and the Internal Revenue Code that govern the use of tax-exempt debt. Other funds are restricted for other special purposes.

Noncurrent Restricted Funds – These funds are restricted as to their specific use. The external Nuclear Decommissioning Trust is restricted for future nuclear decommissioning costs and represents the mandated NRC funding requirements.

The Authority's investments are authorized by the Enabling Act, the Authority's investment policy and the Revenue Obligation Resolution. Authorized investment types include Federal Agency Securities, State of South Carolina General Obligation Bonds and U.S. Treasury Obligations, all of which are limited to a 10 year maximum maturity in all portfolios, except the decommissioning funds. Certificate of Deposits and Repurchase Agreements are also authorized with a maximum maturity of one year.

All debt securities are recorded at their fair value with gains and losses in fair value reflected as a component of non-operating income in the Combined Statements of Revenues, Expenses and Changes in Net Position.

The Authority's investment activity in all fund categories is summarized as follows:

Years Ended December 31,	**2014**	2013
Total Portfolio	(Billions)	
Total investments	**$ 1.8**	$ 1.7
Purchases	**71.2**	55.0
Sales	**71.0**	54.5
Nuclear Decommissioning Portfolios	(Millions)	
Total investments	**$ 206.5**	$ 185.0
Purchases	**691.4**	588.3
Sales	**685.7**	583.1
Unrealized holding gains	**17.0**	7.3
Repurchase Agreements (1)	(Millions)	
Balance at December 31	**$ 304.1**	$ 238.6

(1) Securities underlying repurchase agreements must have a market value of at least 102 percent of the cost of the repurchase agreement and are delivered by broker/dealers to the Authority's custodial agents.

Common deposit and investment risks related to credit risk, custodial credit risk, concentration of credit risk, interest rate risk and foreign currency risk are as follows:

Risk Type	Exposure
Credit Risk - Risk that an issuer of an investment will not fulfill its obligation to the holder of the investments. Measured by the assignment of rating by a nationally recognized statistical rating organization.	As of December 31, 2014 and 2013, all of the agency securities held by the Authority were rated AAA by Fitch Ratings, Aaa by Moody's Investors Service, Inc. and AA+ by Standard & Poor's Rating Services.
Custodial Credit Risk-Investments - Risk that, in the event of the failure of the counterparty to a transaction, an entity will not be able to recover the value of its investment or collateral securities that are in the possession of another party.	As of December 31, 2014 and 2013, all of the Authority's investment securities are held by the Trustee or Agent of the Authority and therefore, there is no custodial risk for investment securities.
Custodial Credit Risk-Deposits - Risk that, in the event of the failure of a depository financial institution, an entity will not be able to recover its deposits or will not be able to recover collateral securities that are in the possession of an outside party.	At December 31, 2014 and 2013, the Authority had no exposure to custodial credit risk for deposits that were uninsured and/or collateral that was held by the bank's agent not in the Authority's name.
Concentration of Credit Risk - The investment policy of the Authority contains no limitations on the amount that can be invested in any one issuer.	Investments in any one issuer (other than U. S. Treasury securities) that represent five percent or more of total Authority investments at December 31, 2014 and 2013 were as follows:

Security Type / Issuer	Fair Value 2014	Fair Value 2013
Federal Agency Fixed Income Securities	(Thousands)	
Federal Home Loan Bank	**$ 597,048**	$ 465,448
Federal National Mortgage Association	**334,680**	255,042
Federal Farm Credit Bank	**319,420**	215,631
Federal Home Loan Mortgage Corp	**225,405**	416,540

Risk Type	Exposure
Interest Rate Risk - Risk that changes in market interest rates will adversely affect the fair value of an investment. Generally, the longer the maturity of an investment, the greater the sensitivity of its fair value to changes in market interest rates.	The Authority manages its exposure to interest rate risk by investing in securities that mature as necessary to provide the cash flow and liquidity needed for operations. The following table shows the distribution of the Authority's investments by maturity at December 31, 2014 and 2013:

	2014		2013	
Investment Type:	**Fair Value (Thousands)**	**Weighted Average Maturity (Years)**	Fair Value (Thousands)	Weighted Average Maturity (Years)
Certificates of Deposits	**$ 1,450**	**0.21**	$ 1,450	0.21
Federal Agency Discount Notes	**465,622**	**0.18**	508,489	0.24
Federal Agency Securities	**1,036,008**	**2.32**	867,850	3.09
Repurchase Agreements	**304,118**	**0.01**	238,599	0.01
U.S. Treasury Notes and Strips	**45,601**	**7.43**	78,240	4.02
Total	**$ 1,852,799**		$ 1,694,628	
Portfolio Weighted Average Maturity		**1.45**		1.88

The Authority holds zero coupon bonds which are highly sensitive to interest rate fluctuations in both the Nuclear Decommissioning Trust and Nuclear Decommissioning Fund. Together these accounts hold $46.1 million par in U.S. Treasury Strips ranging in maturity from August 15, 2015 to May 15, 2039. The accounts also hold $54.0 million par in government agency zero coupon securities in the two portfolios ranging in maturity from June 1, 2017 to April 15, 2030. Zero coupon bonds or U.S. Treasury Strips are subject to wider swings in their market value than coupon bonds. These portfolios are structured to hold these securities to maturity or early redemption. The Authority has a buy and hold strategy for these portfolios. Based on the Authority's current decommissioning assumptions, it is anticipated that no funds will be needed any earlier than 2043. The Authority has no other investments that are highly sensitive to interest rate fluctuations.

Risk Type	Exposure
Foreign Currency Risk - Risk exists when there is a possibility that changes in exchange rates could adversely affect investment or deposit fair market value.	The Authority is not authorized to invest in foreign currency and therefore has no exposure.

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NOTE 5 – LONG-TERM DEBT

Debt Outstanding

The Authority's long-term debt at December 31, 2014 and 2013 consisted of the following:

	2014	2013	Interest Rate(s) (1)	Call Price (2)
	(Thousands)		(%)	(%)
Capitalized Lease Obligations: (final maturity 2014)	**$ 0**	$ 244	N/A	N/A
Revenue Obligations: (mature through 2054)				
1999 Taxable Series B	**0**	1,700	N/A	N/A
2003 Refunding Series A	**0**	10,870	N/A	N/A
2004 Tax-exempt Series A	**0**	45,610	N/A	N/A
2004 Taxable Series B	**3,250**	6,365	4.52	P&I Plus Make-Whole Premium
2004 Series M (4)	**30,380**	30,031	4.25-5.00	100/Accreted Value
2005 Refunding Series A	**105,265**	125,295	5.25-5.50	100
2005 Refunding Series B	**217,065**	222,725	5.00	100
2005 Refunding Series C	**78,150**	78,150	4.125-4.75	100
2005 Series M (4)	**12,836**	12,701	4.00-4.35	100/Accreted Value
2006 Tax-exempt Series A	**13,370**	432,475	4.00-5.00	100
2006 Taxable Series B	**31,250**	59,500	5.05	P&I Plus Make-Whole Premium
2006 Series M (4)	**7,881**	7,811	4.00-4.20	100/Accreted Value
2006 Refunding Series C	**91,820**	114,755	4.00-5.00	100
2007 Series A	**114,400**	290,175	4.10-5.00	100
2007 Refunding Series B	**62,760**	82,855	4.00-5.00	Non-callable
2008 Tax-exempt Series A	**376,985**	391,985	5.00-5.75	100
2008 Taxable Series B	**25,000**	25,000	8.368	P&I Plus Make-Whole Premium
2008 Series M (4)	**21,049**	20,901	3.80-4.80	100/Accreted Value
2009 Tax-exempt Refunding Series A	**83,535**	84,605	3.00-5.00	100
2009 Tax-exempt Series B	**144,875**	160,075	5.00-5.25	100
2009 Taxable Series C	**86,895**	86,970	4.27-6.224	P&I Plus Make-Whole Premium
2009 Tax-exempt Series E	**100,000**	215,755	4.75-5.00	100
2009 Taxable Series F	**100,000**	100,000	5.74	P&I Plus Make-Whole Premium
2010 Series M1 (4)	**27,991**	27,806	2.00-4.30	100/Accreted Value
2010 Refunding Series B	**190,905**	220,665	3.00-5.00	100
2010 Series M2 (4)	**17,402**	17,361	1.60-3.875	100/Accreted Value
2010 Series C (Build America Bonds) (3)	**360,000**	360,000	6.454	P&I Plus Make-Whole Premium
2011 Series M1 (4)	**26,781**	26,655	2.00-4.80	100/Accreted Value
2011 Refunding Series B	**279,600**	282,700	4.00-5.00	Non-callable
2011 Refunding Series C	**135,855**	135,855	4.375-5.00	100
2011 Series M2 (4)	**21,922**	21,935	1.40-4.20	100/Accreted Value
2012 Refunding Series A	**92,985**	98,610	3.00-5.00	100
2012 Refunding Series B	**23,200**	25,200	5.00	Non-callable
2012 Refunding Series C	**80,120**	95,305	5.00	Non-callable
2012 Tax-exempt Series D	**298,785**	310,120	3.00-5.00	100
2012 Taxable Series E	**262,830**	262,830	3.572-4.551	P&I Plus Make-Whole Premium
2012 Series M1 (4)	**21,055**	21,124	1.40-4.00	100/Accreted Value
2012 Series M2 (4)	**18,149**	18,301	1.10-3.70	100/Accreted Value
2013 Series M1 (4)	**23,327**	23,366	1.30-3.90	100/Accreted Value
2013 Tax-exempt Series A	**252,655**	252,655	5.00-5.75	100
2013 Tax-exempt Refunding Series B	**388,730**	388,730	5.00-5.125	100
2013 Taxable Series C	**250,000**	250,000	5.784	P&I Plus Make-Whole Premium
2013 Taxable Series D (LIBOR Index Bonds)	**100,000**	450,000	1 Month LIBOR plus 1.10	100
2013 Tax-exempt Series E	**506,765**	506,765	5.00-5.50	100

Debt Outstanding (continued)

	2014	2013	Interest Rate(s) (1)	Call Price (2)
	(Thousands)		(%)	(%)
2014 Series M1 (4)	**39,764**	0	1.75-4.30	100/Accreted Value
2014 Tax-exempt Series A	**600,000**	0	2.50-6.45	100
2014 Tax-exempt Refunding Series B	**42,275**	0	5.00	100
2014 Tax-exempt Refunding Series C	**704,525**	0	3.00-5.50	100
2014 Taxable Refunding Series D	**31,795**	0	2.906-3.606	P&I Plus Make-Whole Premium
Total Revenue Obligations	**6,504,182**	6,402,292		
Other Long-Term Obligations: (mature through 2016)	**44,956**	44,956		
Less: Current Portion - Long-term Debt	**149,689**	133,671		
Total Long-term Debt - (Net of current portion)	**$ 6,399,449**	$ 6,313,821		

(1) Interest Rates apply only to bonds outstanding as of December 31, 2014.

(2) Call Price may only apply to certain maturities outstanding at December 31, 2014.

(3) These bonds were issued as "Build America Bonds" under the American Recovery and Reinvestment Act of 2009 and are eligible to receive an interest subsidy payment from the United States Department of Treasury in an amount up to 35% of interest payable on the bonds.

(4) Includes Current Interest Bearing Bonds (CIBS) and Capital Appreciation Bonds (CABS).

Changes in Long-Term Debt

Long-term debt (LTD) activity for the years ended December 31, 2014 and 2013 was as follows:

	Gross LTD Beginning Balances	Increases	Decreases	Gross LTD Ending Balances	Current Portion LTD	Total LTD (Net of Current Portion)	Unamortized Debt Discounts and Premiums	LTD-Net Ending Balances
				YEAR 2014 (Thousands)				
Capitalized Lease Obligations	**$ 244**	**$ 0**	**$ (244)**	**$ 0**	**$ 0**	**$ 0**	**$ 0**	**$ 0**
Other Long-Term Obligations	**44,956**	**0**	**0**	**44,956**	**0**	**44,956**	**(467)**	**44,489**
Revenue Obligations	**6,402,292**	**1,420,895**	**(1,319,005)**	**6,504,182**	**149,689**	**6,354,493**	**240,180**	**6,594,673**
Totals	**$ 6,447,492**	**$ 1,420,895**	**$ (1,319,249)**	**$ 6,549,138**	**$ 149,689**	**$ 6,399,449**	**$ 239,713**	**$ 6,639,162**
				YEAR 2013 (Thousands)				
Capitalized Lease Obligations	$ 1,227	$ 0	$ (983)	$ 244	$ 244	$ 0	$ 0	$ 0
Other Long-Term Obligations	0	44,956	0	44,956	0	44,956	(720)	44,236
Revenue Obligations	5,556,566	1,873,808	(1,028,082)	6,402,292	133,427	6,268,865	143,278	6,412,143
Totals	$ 5,557,793	$ 1,918,764	$ (1,029,065)	$ 6,447,492	$ 133,671	$ 6,313,821	$ 142,558	$ 6,456,379

Summary of Long-Term Principal and Interest

Maturities and projected interest payments of long-term debt are as follows:

	PRINCIPAL				
Year Ending December 31,	**Other Long-Term Obligations**	**Revenue Obligations**	**Total Principal**	**TOTAL INTEREST (2)**	**TOTAL**
			(Thousands)		
2015 (1)	$ 0	$ 136,899	$ 136,899	$ 320,602	$ 457,501
2016 (1)	44,956	229,907	274,863	314,596	589,459
2017	0	144,258	144,258	306,867	451,125
2018	0	157,491	157,491	300,414	457,905
2019	0	187,282	187,282	292,591	479,873
2020-2024	0	890,526	890,526	1,339,811	2,230,337
2025-2029	0	714,933	714,933	1,168,522	1,883,455
2030-2034	0	775,041	775,041	999,078	1,774,119
2035-2039	0	855,820	855,820	780,827	1,636,647
2040-2044	0	819,530	819,530	568,149	1,387,679
2045-2049	0	973,875	973,875	320,763	1,294,638
2050-2054	0	618,620	618,620	91,926	710,546
Total	$ 44,956	$ 6,504,182	$ 6,549,138	$ 6,804,146	$ 13,353,284

(1) Years 2015-2016 include projected interest for 2013 Taxable Series D (LIBOR Index Bonds).

(2) Includes Revenue Obligations only - no other applicable interest. Does not reflect impact of subsidy interest payments on 2010 Taxable C (Build America Bonds).

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Summary of Refunded and Defeased Debt and Unamortized Losses

Refunded and defeased debt, original loss on refunding and the unamortized loss at December 31, 2014 are as follows:

Refunding Description		Refunded Debt		Outstanding	Original Loss	Unamortized Loss
				(Thousands)		
Cash Defeasance	$	20,000	1982 Series A	$ 0	$ 2,763	$ 553
Commercial Paper	$	76,050	1973 Series			
		105,605	1977 Series			
		81,420	1978 Series	0	2,099	10
2005 Refunding Series A	$	74,970	1995 Refunding Series A			
		37,740	1995 Refunding Series B			
		20,080	1996 Refunding Series A	0	23,864	6,141
2005 Refunding Series B	$	2,590	1995 Refunding Series A			
		100,320	1995 Refunding Series B			
		192,305	1996 Refunding Series A			
		21,505	1996 Refunding Series B	0	73,749	25,426
2005 Refunding Series C	$	86,335	1993 Refunding Series C	0	12,125	5,790
2006 Refunding Series C	$	105,005	1999 Series A			
		10,000	2002 Series B	0	7,054	543
2007 Refunding Series B	$	105,370	1997 Refunding Series A	0	8,832	1,600
2009 Refunding Series A	$	99,515	1997 Refunding Series A			
		20,125	1998 Refunding Series B	0	8,707	5,726
2010 Refunding Series B	$	30,430	2001 Series A			
		118,600	2002 Series B			
		84,780	2002 Refunding Series D	0	22,954	10,891
2011 Refunding Series B	$	8,990	2002 Refunding Series D			
		291,825	2004 Series A	0	23,287	13,027
2011 Refunding Series C	$	134,715	2002 Series B			
		5,160	2007 Series A	0	4,362	3,770
2012 Refunding Series A	$	73,535	2003 Refunding Series A			
		34,160	2004 Series A	0	12,206	8,372
Feb 2012 Defeasance	$	5,615	2003 Refunding Series A	0	749	639

Summary of Refunded and Defeased Debt and Unamortized Losses (continued)

Refunding Description			Refunded Debt	Outstanding	Original Loss	Unamortized Loss
				(Thousands)		
2013 Refunding Series B	$	209,426	2003 Refunding Series A			
		7,070	2004 Series A			
		5,000	2006 Series A			
		6,565	2007 Series A			
		82,605	2008 Series B			
		1,125	2009 Series B			
		30,158	2011 Series A (LIBOR Index)			
		2,040	2012 Series D	0	14,446	13,719
2013 Refunding Series C	$	35,584	2003 Refunding Series A			
		97,695	2008 Series B	0	4,601	4,310
2014 Refunding Series C &	$	10,870	2003 Refunding Series A			
Taxable Refunding Series D		11,395	2005 Refunding Series A			
		419,105	2006 Series A			
		10,385	2006 Refunding Series C			
		175,775	2007 Series A			
		4,230	2007 Refunding Series B			
		15,000	2008 Series A			
		15,200	2009 Series B			
		12,920	2010 Refunding Series B			
		3,100	2011 Refunding Series B			
		5,625	2012 Refunding Series A			
		2,000	2012 Refunding Series B			
		15,185	2012 Refunding Series C			
		11,335	2012 Series D			
		18,185	2013 Taxable Series D (LIBOR Index)			
		44,075	Expansion Bond Refunding CP	673,240	32,936	32,667
Nov 2014 Defeasance	$	331,815	2013 Taxable Series D (LIBOR Index)	0	1,097	496
Total				$ 673,240	$ 255,831	$ 133,680

Analysis of Prior Year Current Portion of Long-term Debt

As a part of its long-term capital structure plan, the Authority will be involved in a multi-year refinancing plan. As a result, each year certain maturities classified as current portion of long-term debt may be refinanced in the subsequent year prior to the maturity date. Below is an analysis of the 2013 current portion of long-term debt showing the amounts paid as debt service in 2014 and the amount refinanced. The remaining amount represents five percent of the original principal for all outstanding minibond issues.

Analysis of December 31, 2013 Current Portion of Long-term Debt:	(Thousands)
Principal debt service paid from 2014 Revenues	$ 94,004
Refinanced and other:	
2014 maturities refinanced	28,015
5% current portion requirement for original minibond issue amount (1)	11,652
Total	$ 133,671

(1) Represents five percent annual cap on the requirement related to put features on all outstanding minibond issues. This is an accounting entry only and does not impact debt service.

An analysis of the $334,842 current portion of long-term debt at December 31, 2012 showed that $166,393 was debt service paid from 2013 revenues and $158,355 of maturities were refinanced. The remaining $10,094 represented five percent of the original principal for outstanding minibond issues.

Reconciliations of Interest Charges

Years Ended December 31,		**2014**		2013
		(Thousands)		
Reconciliation of interest cost to interest expense:				
Total interest cost	**$**	**317,159**	$	278,274
Capitalized interest		**(31,385)**		(32,751)
Deferred interest expense		**(14,652)**		(22,351)
Interest charged to fuel expense		**(2,133)**		(2,105)
Total interest expense on long-term debt	**$**	**268,989**	$	221,067
Reconciliation of interest cost to interest payments:				
Total interest cost	**$**	**317,159**	$	278,274
Accrued interest - current year		**(79,061)**		(100,159)
Accrued interest - prior year		**100,159**		108,465
Interest released by refundings		**(12,819)**		(5,030)
Accretion on capital appreciation minibonds		**(2,881)**		(2,402)
Adjustment for prior year interest expense		**(93)**		0
Total interest payments on long term debt	**$**	**322,464**	$	279,148

Debt Service Coverage

Years Ended December 31,		**2014**		2013
		(Thousands)		
Operating revenues	**$**	**1,997,347**	$	1,816,576
Other income		**28,084**		9,246
Total revenues and income		**2,025,431**		1,825,822
Operating expenses		**(1,619,224)**		(1,524,182)
Depreciation		**173,743**		196,812
Total expenses		**(1,445,481)**		(1,327,370)
Funds available for debt service prior to distribution to the State		**579,950**		498,452
Distribution to the State		**(20,659)**		(20,394)
Funds available for debt service after distribution to the State	**$**	**559,291**	$	478,058
Debt Service on Accrual Basis:				
Principal on long-term debt	**$**	**108,851**	$	117,994
Interest on long-term debt		**268,989**		221,067
Interest on long-term debt paid from borrowed proceeds		**0**		(12,720)
Long-term debt service paid from Revenues		**377,840**		326,341
Commercial paper and other principal and interest		**7,453**		6,670
Total debt service paid from Revenues	**$**	**385,293**	$	333,011
Debt Service Coverage Ratio:				
Excluding commercial paper and other:				
Prior to distribution to the State		**1.53**		1.52
After distribution to the State		**1.48**		1.46
Including commercial paper and other:				
Prior to distribution to the State		**1.50**		1.49
After distribution to the State		**1.45**		1.43

Fair Value of Debt Outstanding

The fair value of the Authority's debt is estimated based on quoted market prices for the same or similar issues or on the current rates offered to the Authority for debt with the same remaining maturities. Based on the borrowing rates currently available to the Authority for debt with similar terms and average maturities, the fair value of debt was $7.7 billion and $7.0 billion at December 31, 2014 and 2013, respectively.

2014 Bond Market Transactions

Bond market transactions for the year ended December 31, 2014 were as follows:

	Par Amount:		Date Authorized:	
Revenue Obligations, 2014 Series M1	**Par Amount:**	**$39,584,800**	**Date Authorized:**	**May 1, 2014**

Summary:
- Issued Current Interest Bearing Bonds in $500 denominations and Capital Appreciation Bonds in $200 denominations
- Issued directly by the Authority to residents of the State, customers of the Authority, members of electric cooperatives organized under the laws of the State and electric customers of the Bamberg Board of Public Works and the City of Georgetown
- Interest rates range from 1.75 percent in 2019 and 4.30 percent in 2034

Revenue Obligations, 2014 Tax-exempt Series A and Refunding Series B	**Par Amount:**	**$642,275,000**	**Date Authorized:**	**June 13, 2014**

Summary:
- Issued July 9, 2014 at an aggregate all-in true interest cost of 4.90 percent
- Maturities between Dec 1, 2031 and Dec 1, 2054

Revenue Obligations, 2014 Tax-exempt Refunding Series C and Taxable Refunding Series D	**Par Amount:**	**$736,320,000**	**Date Authorized:**	**October 17, 2014**

Summary:
- Issued October 28, 2014 at an aggregate all-in true interest cost of 3.78 percent
- Maturities between Dec 1, 2020 and Dec 1, 2046

Debt Covenant Compliance

As of December 31, 2014 and 2013, the Authority was in compliance with all debt covenants. The Authority's bond indentures provide for certain restrictions, the most significant of which are:

(1) the Authority covenants to establish rates sufficient to pay all debt service, required lease payments, capital improvement fund requirements and all costs of operation and maintenance of the Authority's electric and water systems and all necessary repairs, replacements and renewals thereof; and
(2) the Authority is restricted from issuing additional parity bonds unless certain conditions are met.

All Authority debt (Electric and Water Systems) issued pursuant to the Revenue Obligation Resolution is payable solely from and secured by a lien upon and pledge of the applicable Electric and Water Revenues of the Authority. Revenue Obligations are senior to:
(1) payment of expenses for operating and maintaining the Systems;
(2) payments for debt service on capitalized leases;
(3) payments for debt service on commercial paper; and
(4) payments made into the Capital Improvement Fund.

Bond Outstanding Summary

As of December 31,	**2014**	2013
Outstanding Revenue Obligations	**$6.5 Billion**	$6.4 Billion
Estimated remaining interest payments	**$6.8 Billion**	$5.6 Billion
Issuance years (inclusive)	**2004 through 2014**	1999 through 2013
Maturity years (inclusive)	**2015 through 2054**	2014 through 2053

NOTE 6 – VARIABLE RATE DEBT

The Board has authorized the issuance of variable rate debt not to exceed twenty percent of the aggregate Authority debt outstanding (including commercial paper) as of the last day of the most recent fiscal year for which audited financial statements of the Authority are available. At December 31, 2014, seven percent of the Authority's aggregate debt outstanding was variable rate. The lien and pledge of Revenues securing variable rate debt issued as Revenue Obligations is senior to that securing commercial paper.

Commercial paper is issued for valid corporate purposes with a term not to exceed 270 days. The information related to commercial paper was as follows:

Years Ended December 31,		**2014**		2013
Commercial paper outstanding (000's)	**$**	**410,139**	$	372,073
Effective interest rate (at December 31)		**0.15%**		0.13%
Average annual amount outstanding (000's)	**$**	**341,974**	$	374,497
Average maturity		**51 Days**		45 Days
Average annual effective interest rate		**0.13%**		0.17%

As of December 31, 2014 and 2013, the Authority had Revolving Credit Agreements with Barclays Bank PLC, J.P. Morgan Chase Bank, N.A., TD Bank, N.A., U.S. Bank, N.A., and Wells Fargo Bank, N.A. totaling $800.0 million for both years. These agreements are used to support the Authority's issuance of commercial paper. There were no borrowings under the agreements during 2014 or 2013.

NOTE 7 – SUMMER NUCLEAR STATION

Nuclear Unit 1 - The Authority and SCE&G are parties to a joint ownership agreement providing that the Authority and SCE&G shall own Unit 1 at the Summer Nuclear Station with undivided interests of 33 1/3 percent and 66 2/3 percent, respectively. SCE&G is solely responsible for the design, construction, budgeting, management, operation, maintenance and decommissioning of Unit 1 and the Authority is obligated to pay its ownership share of all costs relating thereto. The Authority receives 33 1/3 percent of the net electricity generated. In 2004, the NRC granted a twenty-year extension to the operating license for Unit 1, extending it to August 6, 2042.

Authority's Share of Summer Nuclear - Unit 1

Years Ended December 31,		**2014**		2013
		(Millions)		
Plant balances before depreciation	**$**	**521.3**	$	515.9
Accumulated depreciation		**332.9**		326.7
Operation & maintenance expense		**83.9**		90.2

Nuclear fuel costs are being amortized based on energy expended using the unit-of-production method. Through April 2014, costs include a component for disposal of spent nuclear fuel; however, in May, the Department of Energy (DOE) suspended the collection of spent fuel disposal fees. Fuel amortization and disposal fees are included in fuel expense and recovered through the Authority's rates.

In 2002, SCE&G commenced a re-racking project of the on-site spent fuel pool. The new pool storage capability will permit full core off-load through 2017. SCE&G has signed contracts with HOLTEC International, The Shaw Group, Inc. and Westinghouse Electric Company, Inc. (Westinghouse) to build a licensed Independent Spent Fuel Storage Installation (ISFSI) to commence receiving fuel in 2016.

The NRC requires a licensee of a nuclear reactor to provide minimum financial assurance of its ability to decommission its nuclear facilities. In compliance with the applicable NRC regulations, the Authority established an external trust fund and began making deposits into this fund in September 1990. In addition to providing for the minimum requirements imposed by the NRC, the Authority makes deposits into an internal fund in the amount necessary to fund the difference between a site-specific decommissioning study completed in 2012 and the NRC's imposed minimum requirement. Based on these estimates, the Authority's one-third share of the estimated decommissioning costs of Unit 1 equals approximately $315.1 million in 2012 dollars. As deposits are made, the Authority debits FERC account 532 - Maintenance of Nuclear Plant, an amount equal to the deposits made to the internal and external trust funds. These costs are recovered through the Authority's rates.

Based on current decommissioning cost estimates, these funds, which totaled approximately $206.5 million (adjusted to market) at December 31, 2014, along with future deposits into the external decommissioning trust and investment earnings, are estimated to provide sufficient funds for the Authority's one-third share of the total decommissioning costs.

Nuclear Units 2 and 3 - The Authority and SCE&G are constructing and planning to operate two additional nuclear generating units at Summer Nuclear Station (Units 2 and 3) and submitted an application to the NRC in March 2008 for a combined Construction and Operating License (COL) for each of the two new units. On May 22, 2008, the Authority's Board authorized the Authority to execute a Limited Agency Agreement appointing SCE&G to act as the Authority's agent in connection with the performance of an Engineering, Procurement and Construction (EPC) Agreement. On May 23, 2008, SCE&G, acting for itself and as agent for the Authority, entered into an EPC Agreement with Westinghouse and Stone & Webster, Inc., (a subsidiary of The Shaw Group, Inc.), for the engineering, procurement and construction of two 1,117 MW nuclear generating units. Chicago Bridge & Iron Company acquired The Shaw Group, Inc. in February 2013.

On October 20, 2011, the Authority and SCE&G entered into a Design and Construction Agreement. Among other things, the Design and Construction Agreement allows either or both parties to withdraw from the project under certain circumstances. Also on October 20, 2011, the Authority and SCE&G entered into an Operating and Decommissioning Agreement with respect to the two units. Both the Design and Construction Agreement and the Operating and Decommissioning Agreement define the conditions under which the Authority or SCE&G may convey an undivided ownership interest in the new units to a third party. Together the Design and Construction Agreement and the Operating and Decommissioning Agreement provide for a 45 percent ownership interest by the Authority in each of the two new units and replace the Amended and Restated Bridge Agreement which had governed the relationship between the Authority and SCE&G.

The Authority received the COLs on March 30, 2012. On April 5, 2012, the Authority's Board authorized the Authority to expend up to $4.9 billion to fund the Authority's share of the EPC Agreement and associated Owner's Costs to complete the project. Construction is progressing and the following significant milestones were completed in 2014:

Month Completed	Unit	Milestones
April	3	Completed erection of Module CR10 (Containment Vessel Bottom Head Support)
May	2	Set Module CA20 (Portion of Auxiliary Building - Contains Refueling Canal, Spent Fuel Pool)
May	3	Set Containment Vessel Bottom Head
June	2	Set Containment Vessel Lower Ring
December	2	Set Module CA05 inside Containment Vessel (CVS/Access Tunnel/PXS)

The Authority anticipates that Unit 2 will go into service by June 2019, and Unit 3 will go into service approximately one year after Unit 2.

As part of its capital improvement program, the Authority has evaluated its level of participation in the new units. Due to developments since initiation of the project, the Authority has taken actions necessary to reduce its 45 percent ownership interest. In January 2014, the Authority entered into an agreement whereby SCE&G will purchase from the Authority an additional 5% interest in the project. Under the terms of the agreement, SCE&G will own 60% of the new nuclear units and the Authority, 40%. The 5% ownership interest will be acquired in three stages, with 1% to be acquired at the commercial operation date of the first new nuclear unit, an additional 2% to be acquired no later than the first anniversary of such commercial operation date, and the final 2% to be acquired no later than the second anniversary of such commercial operation date. Beginning 2011, the Authority deferred a portion of interest expense representing the amount related to the assumed ownership reduction. In 2013, the Authority continued deferring and began capitalizing portions of related interest expense based on revised ownership assumptions.

NOTE 8 – LEASES

The Authority made the final payment related to the capital lease contracts with Central on November 26, 2014. At December 31, 2014 and 2013, the outstanding principal balances were $0 and $244, respectively.

Information related to property under capital leases and operating lease payments follows:

Years Ended December 31,		2014		2013
		(Millions)		
Property under capital leases:				
Property balances	**$**	**0.0**	$	10.2
Accumulated depreciation		**0.0**		8.7
Operating lease payments (1)		**2.1**		1.7

(1) Includes periodic leased coal car expenses which are initially reflected in fuel inventory and subsequently reported in fuel expense based on tons burned.

Expiration term of current coal car leases: (2)	March and December 2015

(2) The maximum amount due for coal car leases for 2015 is $672,300.

Hydroelectric generating facility lease:

- Automatically extended for five-year periods
- May be terminated by either party by giving a two-year notice
- Obligation is $600,000 per year plus operating expenses

NOTE 9 – CONTRACTS WITH ELECTRIC POWER COOPERATIVES

Central is a generation and transmission cooperative that provides wholesale electric service to each of the 20 distribution cooperatives which are members of Central. Power supply and transmission services are provided to Central in accordance with a power system coordination and integration agreement (the Coordination Agreement). Under this agreement, the Authority is the predominant supplier of energy needs for Central, excluding amounts supplied by others to five of its member cooperatives located in the upper part of the State which is further described below, energy Central receives from the Southeastern Power Administration (SEPA), minimal amounts provided by Broad River Electric Cooperative's ownership interest in a small run of the river hydroelectric plant and negligible amounts purchased from others.

Central, under the terms of the Coordination Agreement, has the right to audit costs billed to them through the Coordination Agreement. Any differences found as a result of this process are accrued if they are probable and estimable. To the extent that differences arise, prospective adjustments are made to the cost of service and are reflected in operating revenues in the accompanying Combined Statements of Revenues, Expenses and Changes in Net Position. Such adjustments in 2014 and 2013 were not material to the Authority's overall operating revenue.

In September 2009, the Authority and Central entered into an agreement which, among other things, would permit Central to purchase the electric power and energy requirements necessary to serve five of its member cooperatives located in the upper part of the State that were formerly members of Saluda: Blue Ridge Electric Cooperative, Inc., Broad River Electric Cooperative, Inc., Laurens Electric Cooperative, Inc., Little River Electric Cooperative, Inc. and York Electric Cooperative, Inc. (the Upstate Load) from a supplier other than the Authority.

The Upstate Load began transitioning to the new supplier in 2013. The transition will continue through 2019 and will amount to approximately 900 MW.

In April and May 2013, the Central and Authority Boards, respectively, approved an Amendment to the Central Agreement (the Amended Central Agreement). This amendment provides that both parties waive their rights to terminate the agreement until at least December 31, 2058. The Amended Central Agreement provides for closer cooperation on planning of future resources, gives Central the ability to "opt-out" of future generation resources, and provides for cost recovery of all resources completed or under construction as of the amendment effective date, including Summer Nuclear Units 2 and 3.

NOTE 10 – COMMITMENTS AND CONTINGENCIES

Budget – The Authority's 2015 three-year capital budget is as follows:

Years Ending December 31,	2015	2016	2017
		(Millions)	
Environmental compliance	$ 39.9	$ 8.4	$ 17.8
General improvements	258.2	215.0	182.3
Summer Nuclear Units 2 and 3 (1)	509.6	574.6	593.0
Total capital budget (2)	$ 807.7	$ 798.0	$ 793.1

Budget Assumptions:
(1) Construction cash flows for 2014 and the 2015-2017 budgets reflect 45 percent ownership. Subsequent cash flows will be reduced in accordance with the projected ownership sale date. Total estimated project cost including transmission is $4,514.8 million.
(2) Will be financed by internally generated funds, taxable and tax-exempt debt.

Purchase Commitments - The Authority has contracted for long-term coal purchases under contracts with estimated outstanding minimum obligations after December 31, 2014. The disclosure of minimum obligations (including market re-opener contracts) shown below is based on the Authority's contract rates and represents management's best estimate of future expenditures under long-term arrangements.

Years Ending December 31,	With Re-openers (All Tons) (1)	Without Re-openers (Fixed Tons) (2)
	(Thousands)	
2015	$ 359,924	$ 359,924
2016	249,592	249,592
2017	162,137	162,137
2018	146,135	146,135
2019	76,418	76,418
Total	$ 994,206	$ 994,206

(1) Includes tons which the Authority can elect not to receive.

(2) Includes tons which the Authority must receive.

The Authority has the following outstanding obligations under existing long-term capacity and purchased power contracts as of December 31, 2014:

Contracts with Minimum Fixed Payment Obligations

Number of Contracts	Delivery Beginning	Remaining Term	Obligations (Millions)
1	1985	20 Years	$ 52.0
1	2012	1 Year	23.2

Contracts with Power Receipt and Payment Obligations (1)

Number of Contracts	Delivery Beginning	Remaining Term	Obligations (Millions)
1	2010	11 Years	$ 213.9
1	2013	19 Years	18.1
2	2013	29 Years	652.9
1	2013	19 Years	8.2
1	2015	25 Years	433.9

(1) Payment required upon receipt of power. Assumes no change in indices or escalation.

The Authority entered into agreements effective October 1, 2008, whereby New Horizon Electric Cooperative, Inc. assigned its interests, rights and obligations in contracts with Duke Energy Corporation and SCE&G for network integration transmission service to the Authority. The agreements are for network transmission service for the Upstate Load as defined in Note 9 – Contracts with Electric Power Cooperatives. A payment schedule for these agreements shows that $8.7 million will be due in 2015, with the remaining $50.5 million through the end of the contract term in 2023. However, a majority of the Upstate Load will transition to a new supplier as stated in Note 9 and the Authority's obligation for transmission service for this load will decrease in approximately the same proportion. At the end of the transition period, the Authority shall no longer be responsible for purchasing transmission service for the load served by the new supplier.

CSX Transportation, Inc. (CSX) provides substantially all rail transportation service for the Authority's Cross and Winyah coal-fired generating stations. The Authority also interchanges with some short line railroads via CSX for the movement of coal as well. The CSX contract, effective January 1, 2011, continues to apply a price per ton of coal moved, along with a mileage based fuel surcharge and minimum tonnage obligation. The Authority's rail contract expires on December 31, 2015 and the process of renegotiating an extended contract with CSX has begun.

The Authority has commitments for nuclear fuel, nuclear fuel conversion, enrichment and fabrication contracts for Summer Nuclear Units 1, 2 and 3. As of December 31, 2014, these contracts total approximately $443.5 million over the next 23 years.

In 2010, the Authority amended the Rainey Generating Station Long-Term Parts and Long-Term Service Contract with General Electric International, Inc. (GEII). In lieu of exercising its option to terminate the Contract for convenience and to pursue non original equipment manufactured parts and services, the Authority negotiated an amendment with reduced pricing for maintenance and fixed escalation. The contract provides a contract performance manager (CPM), initial spare parts, parts and services for specified planned maintenance outages, remote monitoring and diagnostics of the turbine generators and combustion tuning for the gas turbines.

The amended contract value is approximately $97.2 million, excluding escalation and adjustments for liquidated damages and bonuses. The contract term extends through the second major inspection for Rainey 1 (expected to be completed in 2018). Rainey 2A and 2B have reached the contract "performance end date." The Authority's estimated remaining commitment on the contract is $36.6 million, including escalation, and the Authority is currently exploring options for these units, including a potential extension of the GEII contract. The contract can be terminated for convenience at the end of 2015. The Authority's Board has approved recovery of contract expenditures on a straight-line basis over the term of the contract.

Effective November 1, 2000, the Authority contracted with Transcontinental Gas Pipeline Corporation (TRANSCO) to supply gas transportation needs for its Rainey Generating Station. This is a firm service agreement for the transportation of 80,000 decatherms per day.

Risk Management - The Authority is exposed to various risks of loss related to torts; theft of, damage to, and destruction of assets; business interruption; and errors and omissions. The Authority purchases commercial insurance to cover these risks, subject to coverage limits and various exclusions. Settled claims resulting from these risks did not exceed commercial insurance coverage in 2014. Policies are subject to deductibles ranging from $500 to $2.0 million, with the exception of named storm losses which carry deductibles from $2.0 million up to $5.0 million. Also a $1.4 million general liability self-insured layer exists between the Authority's primary and excess liability policies. During 2014, there were minimal payments made for general liability claims.

The Authority is self-insured for auto, dental, worker's compensation and environmental incidents that do not arise out of an insured event. The Authority purchases commercial insurance, subject to coverage limits and various exclusions, to cover automotive exposure in excess of $2.0 million per incident. Risk exposure for the dental plan is limited by plan provisions. Estimated exposure for worker's compensation is based on an annual actuarial study using loss and exposure information valued as of June 30, 2014. In addition, there have been no third-party claims regarding environmental damages for 2014 or 2013.

Claim expenditures and liabilities are reported when it is probable that a loss has occurred and the amount of the loss can be reasonably estimated. The amount of the self-insurance liabilities for auto, dental, worker's compensation and environmental remediation is based on the best estimate available. Changes in the reported liability were as follows:

Years Ended December 31,	**2014**	2013
	(Thousands)	
Unpaid claims and claim expense at beginning of year	**$ 2,538**	$ 1,778
Incurred claims and claim adjustment expenses:		
Add: Provision for current year events	**2,043**	2,940
Less: Payments for current and prior years	**3,260**	2,180
Total unpaid claims and claim expenses at end of year	**$ 1,321**	$ 2,538

The Authority pays insurance premiums to certain other State agencies to cover risks that may occur in normal operations. The insurers promise to pay to, or on behalf of, the insured for covered economic losses sustained during the policy period in accordance with insurance policy and benefit program limits. The State assumes all risks for the following:

(1) claims of covered employees for health benefits covered through South Carolina Public Employee Benefit Authority (PEBA); not applicable for worker's compensation injuries; and
(2) claims of covered employees for basic long-term disability and group life insurance benefits (PEBA and Retirement System).

Employees elect health coverage through the State's self-insured plans. However, additional group life and long-term disability premiums are remitted to commercial carriers. The Authority assumes the risk for claims of employees for unemployment compensation benefits and pays claims through the State's self-insured plan.

Nuclear Insurance - The maximum liability for public claims arising from any nuclear incident has been established at $13.6 billion by the Price-Anderson Indemnification Act. This $13.6 billion would be covered by nuclear liability insurance of $375.0 million per reactor unit, with potential retrospective assessments of up to $127.3 million per licensee for each nuclear incident occurring at any reactor in the United States (payable at a rate not to exceed $18.9 million per incident, per year). Based on its one-third interest in Summer Nuclear Unit 1, the Authority could be responsible for the maximum assessment of $42.4 million, not to exceed approximately $6.3 million per incident, per year. This amount is subject to further increases to reflect the effect of (i) inflation, (ii) the licensing for operation of additional nuclear reactors and (iii) any increase in the amount of commercial liability insurance required to be maintained by the NRC.

Additionally, SCE&G and the Authority maintain, with Nuclear Electric Insurance Limited (NEIL), $1.5 billion primary and $1.25 billion excess property and decontamination insurance to cover the costs of cleanup of the facility in the event of an accident. SCE&G and the Authority also maintain accidental outage insurance to cover replacement power costs (within policy limits) associated with an insured property loss. In addition to the premiums paid on these three policies, SCE&G and the Authority could also be assessed a retrospective premium, not to exceed ten times the annual premium of each policy, in the event of property damage to any nuclear generating facility covered by NEIL. Based on current annual premiums and the Authority's one-third interest, the Authority's maximum retrospective premium would be approximately $6.4 million for the primary policy, $2.2 million for the excess policy and $1.6 million for the accidental outage policy.

SCE&G and the Authority maintain builder's risk insurance and marine cargo insurance for the Summer Nuclear Units 2 and 3 construction. The builder's risk policy provides coverage of $2.75 billion accidental nuclear property damage with a sub-limit of $500.0 million for accidental property damage that is caused by or results from any covered peril other than radioactive contamination resulting from nuclear reaction, nuclear radiation or the release of radioactive materials, with deductibles ranging from $250,000 to $5.0 million. This policy also carries a potential retrospective premium of approximately $42.0 million. Based on the Authority's current 45 percent ownership interest, the Authority's maximum retrospective premium would be approximately $18.9 million. The marine cargo/transit policy provides coverage of $300.0 million, with deductibles ranging from $25,000 to $75,000.

The Authority is self-insured for any retrospective premium assessments, claims in excess of stated coverage or cost increases due to the purchase of replacement power associated with an uninsured event. Management does not expect any retrospective assessments, claims in excess of stated coverage or cost increases for any periods through December 31, 2014.

Clean Air Act - The Authority endeavors to ensure that its facilities comply with applicable environmental regulations and standards.

In addition to the existing Clean Air Act (CAA) Federal Acid Rain Program, the Environmental Protection Agency (EPA) has promulgated and is implementing the Cross State Air Pollution Rule (CSAPR) for SO2 and NOx emissions, effective January 1, 2015.

CSAPR was EPA's replacement for the Clean Air Interstate Rule (CAIR). After going through the U.S. Court of Appeals process for the D.C. Circuit over the last several years, CSAPR is now in effect due to several court decisions in 2014. Emission budgets applied beginning January 1, 2015 for the annual programs, and will apply on May 1, 2015 for the ozone-season NOx program. This rule is not expected to negatively impact Santee Cooper.

The Authority has been operating under a settlement agreement, called the Consent Decree, which became effective June 24, 2004. The settlement with EPA and the South Carolina Department of Health and Environmental Control (DHEC) was related to certain environmental issues associated with coal-fired units. It involved the payment of a civil penalty, an agreement to perform certain environmentally beneficial projects and incur capital costs to achieve emission reductions. Capital costs have been partially offset by a reduced need to purchase emission credits. All emissions reduction projects required by the Consent Decree have been completed.

Currently, there are both legislative and regulatory efforts to reduce greenhouse gas emissions. The Authority continues to review proposed greenhouse gas regulations to assess potential impacts to its operations. In 2010, EPA finalized the Prevention of Significant Deterioration (PSD) Tailoring Rule for regulating greenhouse gases through the PSD permitting process under the existing CAA. EPA issued Best Available Control Technology (BACT) Guidance in 2010 for use under the rule effective July 1, 2011. In 2014, EPA proposed three separate rules for (1) new, (2) existing, and (3) modified and reconstructed Electric Generating Units (EGU). Final rules are anticipated to be released midsummer 2015. The Authority will continue to monitor both regulatory and legislative efforts related to greenhouse gas emissions and assess potential impacts to its operations.

In place of the vacated federal Clean Air Mercury Rule (CAMR), South Carolina utilities and DHEC finalized a Memorandum of Agreement (MOA) in which the Authority committed to install and certify mercury Continuous Emissions Monitoring Systems (CEMS) at a set of agreed-upon coal-fired units and collaborate with the South Carolina utilities and DHEC to provide support for a state-wide assessment evaluating the mercury deposition resulting from coal-fired power plants in South Carolina. In 2009, the mercury CEMS were installed at the specified Authority units and utilities began initial reporting. There are no cap and trade or emissions limitations requirements per the MOA.

Through the maximum achievable control technology (MACT) regulatory process, the EPA has proposed the Utility MACT regulations to reduce the emissions of mercury and other hazardous air pollutants (HAPs) from coal and oil-fired electric utility steam boilers. As a part of EPA rule development, the Authority participated in the EPA's mandatory Information Collection Request (ICR) for mercury and other HAPs for its coal-fired and oil-fired units. The ICR required facility and fuel information as well as stack testing at Cross, Winyah and Jefferies generating stations.

The proposed MACT rule was released in March 2011 with a public notice comment period. The Authority submitted comments to the proposed rule. The final MACT rule, renamed the Mercury and Air Toxics Standard (MATS) became effective April 16, 2012, with a compliance deadline for existing units of April 16, 2015. Santee Cooper applied for and received a compliance extension for its Cross and Winyah coal-fired EGUs for April 16, 2016 granted by DHEC and in accordance with the regulation.

The MATS rule includes emissions limitations for mercury, acid gases and other HAPs from existing and new coal-fired and oil-fired electric utility steam units. This is EPA's first national standard to reduce mercury and other air toxics from coal-fired and oil-fired power plants.

On November 26, 2014, the US EPA completed the federally mandated 5-year review of the national ambient air quality standards (NAAQS) and proposed a revised (more stringent) ground-level ozone standard range. This applies to both the primary (public health) and secondary (public welfare) standards. The 90-day public comment period began December 17, 2014. By Court Order, the binding Final Rule is due to be promulgated on or before October 1, 2015. According to DHEC information several counties will be at risk of nonattainment with the upper boundary of the proposed range. All counties in South Carolina will be at risk of nonattainment with the lower boundary of the proposed range. The Authority is evaluating the proposed rule and plans to submit comments.

Safe Drinking Water Act - The Authority continues to monitor regulatory issues impacting drinking water systems at the Authority's regional water systems, generating stations, substations and other auxiliary facilities. DHEC has regulatory authority of potable water systems in South Carolina under The State Primary Drinking Water Regulation, R.61-58; the Authority endeavors to manage its potable water systems in compliance with R.61-58.

Clean Water Act - The Clean Water Act (CWA) prohibits the discharge of pollutants, including heat, from point sources into waters of the United States, except as authorized in the National Pollutant Discharge Elimination System (NPDES) permit program. DHEC has been delegated NPDES permitting authority by the EPA and administers the NPDES permit program for the State.

Wastewater discharges from the generating stations and the regional water plants are governed by NPDES permits issued by DHEC. Further, the storm water from the generating stations must be managed in accordance with the State's NPDES Industrial General Permit for storm water discharges. Storm water from construction activities must also be managed under the State's NPDES General Permit for storm water discharges from construction activity. The Authority constantly strives to operate in compliance with these permits.

The CWA, under Section 316(b), requires that cooling water intake structures (CWIS) reflect the best technology available for minimizing adverse environmental impacts, such as the impingement of fish and shellfish on the intake structures and the entrainment of eggs and larvae through cooling water systems. The EPA published the final rule under the CWA Section 316(b) on August 15, 2014, and the rule became effective October 15, 2014. The final rule contains some significant deviations from the proposed rule, such as an outline of seven compliance options and an extended reporting deadline. The Authority will continue to work with the regulatory agencies on implementation.

The EPA has regulations under the CWA relating to Spill Prevention Control and Counter-measures (SPCC). These regulations require that applicable facilities, which include generating stations, substations and auxiliary facilities, maintain SPCC plans to meet certain standards. The Authority continually works to be in compliance with these regulations.

In 2013, EPA issued a proposed rule to amend the Steam Electric effluent guidelines (ELG) and standards that would require additional control and treatment of wastewater discharges from the generating stations. The proposal, if enacted, is expected to require more control of heavy metals removed by air pollution control (ash and FGD sludge) and new internal outfalls that will likely require additional wastewater treatment systems to meet the new limitations. Under the proposed approach, new requirements for existing power plants would be phased in between 2017 and 2022. EPA also announced its intention to align this rule with a related rule for coal combustion residuals (CCRs). On April 19, 2014, EPA and environmental groups agreed to extend the deadline for the final rule until September 30, 2015.

Waters of the U.S. (WOUS). On April 21, 2014, the EPA and United States Army Corps of Engineers (Corps) published for public comment a proposed rule defining the scope of waters protected under the CWA. The proposed rule seeks to clarify which streams, wetlands and other waters are considered WOUS and, thus subject to permitting requirements under the CWA. The joint proposed rule will affect project development and operations across the energy, water, construction, building, agricultural and transportation sectors. The Authority submitted comments to the rule. The Authority cannot fully estimate the potential cost of compliance with the proposed rule.

Hazardous and Non-Hazardous Substances, Wastes and Byproducts - Section 311 of the CWA imposes substantial penalties for spills of Federal EPA-listed hazardous substances into water and for failure to report such spills. The Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA) provides for the reporting requirements to cover the release of hazardous substances into the environment. Additionally, the EPA regulations under the Toxic Substances Control Act (TSCA) impose stringent requirements for labeling, handling, storing and disposing of polychlorinated biphenyls (PCBs) and associated equipment.

Under the CERCLA and Superfund Amendments and Reauthorization Act (SARA), the Authority could be held responsible for damages and remedial action at hazardous waste disposal facilities utilized by it, if such facilities become part of a Superfund effort. Moreover, under SARA, the Authority must comply with a program of emergency planning and a "Community Right-To-Know" program designed to inform the public about more routine chemical hazards present at the facilities. Both programs have stringent enforcement provisions. The Authority endeavors to comply with the applicable provisions of TSCA, CERCLA and SARA, but it is not possible to determine if some liability may be imposed in the future for past waste disposal or compliance with new regulatory requirements. The Authority strives to comply with all aspects of Resource Conservation and Recovery Act (RCRA) regarding appropriate disposal of chemical wastes.

The Authority generates solid waste associated with the combustion of coal, the vast majority of which is fly ash, bottom ash, scrubber sludge and gypsum. These wastes, known as Coal Combustion Residuals (CCRs), are exempt from hazardous waste regulation under the RCRA. On December 19, 2014, the EPA issued a rule to regulate CCRs as a RCRA Subtitle D, nonhazardous waste. The rule establishes the following national minimum criteria for existing and new CCR landfills and surface impoundments:

- Location restrictions;
- Design and construction requirements;
- Operating criteria such as inspections, structural integrity evaluations and fugitive dust controls;
- Groundwater monitoring and corrective action;
- Closure requirements and post-closure care;
- Record keeping, notifications and internet posting requirements.

No firm estimates relative to the cost of implementing this regulation, have been made at this time since the rule is still under review. However, the Authority has budgeted $320.0 million through 2019 for compliance purposes.

The Solid Waste Disposal Act and Energy Policy Act give EPA authority to regulate Underground Storage Tanks (USTs). EPA regulations concerning USTs are contained in 40 CFR Parts 280-282. DHEC has granted state program approval in 2002 and regulates USTs under R. 61-92, Part 280 dated 2008. This regulation provides requirements for the design, installation, operation, closure, release detection, reporting and corrective action and financial responsibility. The Authority's corporate policy number 2-11-02 provides guidance for the proper management and monitoring of USTs for environmental and regulatory compliance.

At Cross Generating Station, dry disposal of CCRs into an industrial Class 2 solid waste landfill is governed by a Consent Agreement executed on April 29, 2011 between the Authority and DHEC, which provides for operation of the landfill until December 31, 2015. The Authority has received all necessary permits to construct a Class 3 solid waste landfill at Cross Generating Station and construction is underway. The Authority expects to complete construction and place the landfill into operation prior to December 31, 2015. The Authority will dispose of CCRs into the Class 3 solid waste landfill after that date.

The Authority is in the process of retiring units and ancillary facilities at Grainger and Jefferies generating stations. The Authority plans to properly close ash ponds at these facilities by excavation and beneficial use. A closure plan for the Grainger Generating Station ash ponds has been approved by DHEC and closure through beneficial use is in progress. Development of a similar closure plan for Jefferies ash ponds is in progress. In addition, the Authority is planning to close the Grainger cooling pond in accordance with DHEC requirements.

Pollution Remediation Obligations – The Authority follows GASB 49 which addresses standards for pollution (including contamination) remediation obligations for activities such as site assessments and cleanups. GASB 49 does not include standards for pollution remediation obligations that are addressed elsewhere. Examples of obligations addressed in other standards include pollution prevention and control obligations for remediation activities required upon the retirement of an asset, such as ash pond closure and post-closure care and nuclear power plant decommissioning.

The Authority recorded $40,000 and $15,000 for pollution remediation liabilities for the years ended December 31, 2014 and 2013, respectively. The method used to estimate the liabilities consists of weighting a range of possible estimated job cost amounts and calculating a weighted average cost. The weights and estimated costs are developed using professional engineering judgment acquired through years of estimating and completing many pollution remediation projects.

Homeland Security – The Department of Homeland Security (DHS) was established by the Homeland Security Act of 2002, a portion of which relates to anti-terrorism standards at facilities which store or process chemicals. The Authority has been proactive in conducting security assessments at its facilities and will continue to strive to comply with these evolving regulations.

Legal Matters – Except as noted below, there are no actions, suits, or governmental proceedings pending or, to the knowledge of the Authority, threatened before any court, administrative agency, arbitrator or governmental body which would, if determined adversely to the Authority, have a material adverse effect on its financial condition. However, even if determined adversely to the Authority, no such actions, suits, or governmental proceedings would have a material adverse effect on the Authority's ability to transact its business or meet its obligations under the Revenue Obligation Resolution.

Santee River Corps Claim. As of March 2010, the Authority had paid approximately $221.0 million, including interest, in settlement of a lawsuit brought by a number of landowners located along the Santee River primarily in Williamsburg and Georgetown Counties, South Carolina. The plaintiffs claimed damage to their real estate as a result of flooding that has occurred since the Corps' Cooper River Rediversion Project was completed in 1985. The Authority also paid an additional $10.4 million in costs and attorneys' fees to the plaintiffs in August, 2011. The Authority pursued an indemnification claim against the Corps before the Armed Services Board of Contract Appeals (ASBCA).

On February 14, 2013, ASBCA ruled that the Authority is entitled to reimbursement from the Corps for approximately $234.9 million for costs incurred as a result of the Santee River litigation. The award by the ASBCA also includes interest on the indemnification amount pursuant to the Contract Disputes Act, calculated from August 20, 2001, until paid. On June 11, 2013, the Corps appealed the ASBCA decision to the United States Court of Appeals for the Federal Circuit.

On May 28, 2014, the United States Department of Justice, acting on behalf of the Corps, entered into a settlement with the Authority. Pursuant to the Settlement Agreement, the United States was required to pay the Authority $257.1 million plus interest on that amount running from May 1, 2014 (The settlement amount consists of the approximate principal and interest amounts of $234.9 million and $22.2 million, respectively). On August 1, 2014 the Authority received payment of approximately $258.5 million, which fully resolved the claim.

Horry Electric Cooperative, Inc. (Horry Co-op) Suit. In May 2013, Horry Co-op, a member of Central, sued the Authority seeking indemnification for claims in a class action lawsuit brought against Horry Co-op by certain of its customers. The customers allege mold damage to their homes was caused by vapor barriers installed in accordance with the Authority's energy efficiency recommendations. Horry Co-op's complaint alleges the Authority knew the vapor barrier could cause moisture problems but failed to disclose the information to Horry Co-op and failed to advise Horry Co-op that the vapor barrier should be a recommendation rather than a requirement. A settlement has been reached in the underlying class action lawsuit against Horry Co-op. The settlement provides for the establishment of two funds, totaling $6.0 million dollars, to pay the claims of the class members. The Authority has been informed that as of the deadline for filing claims approximately $1.4 million dollars in claims and attorney fees have been paid. The Authority filed a motion to dismiss the claims brought against it by Horry Co-op. On June 11, 2014, the Court dismissed the suit, ruling that the majority of the claims were dismissed with prejudice and that the claim for equitable indemnification was dismissed without prejudice. Horry Co-op has appealed the dismissal of the suit. The Authority cannot predict the outcome of the appeal. On October 20, 2014 the Authority was served with an additional complaint filed by Horry Co-op in Horry County. The complaint alleges a single cause of action for indemnity arising out of the same underlying factual allegations as the original complaint filed in May of 2013. The Authority has filed a motion to dismiss the complaint. The Authority cannot predict the outcome of this lawsuit.

NOTE 11 – RETIREMENT PLAN

Substantially all Authority regular employees must participate in one of the components of the South Carolina Retirement System (SCRS), a cost sharing, multiple-employer public employee retirement system, which was established by Section 9-1-20 of the South Carolina Code of Laws.

The payroll for active employees covered by SCRS was as follows:

Years Ended December 31,	**2014**	2013	2012
		(Millions)	
Payroll for Active Employees	**$ 131.5**	$ 126.9	$ 125.7

Vested employees (Class Two Members) who retire at age 65 or with 28 years of service at any age are entitled to a retirement benefit, payable monthly for life. Vested employees (Class Three Members) who retire at age 65 or meet the "rule of 90 requirements" (i.e., the total of the member's age and the member's creditable service equals at least 90 years), are entitled to a retirement benefit, payable monthly for life. The annual benefit amount is equal to 1.82 percent of their average final compensation times years of service. Benefits fully vest on reaching five years of service for Class Two Members and eight years for Class Three Members. Reduced retirement benefits are payable as early as age 60 with vested service or 55 with 25 years of service for Class Two Members. The SCRS also provides death and disability benefits. Benefits are established by State statute.

Effective January 1, 2001, Section 9-1-2210 of the South Carolina Code of Laws allowed SCRS employees eligible for service retirement to participate in the Teacher and Employee Retention Incentive (TERI) Program. TERI participants may retire and begin accumulating retirement benefits on a deferred basis without terminating employment for up to five years. Upon termination of employment or at the end of the TERI period, whichever is earlier, participants will begin receiving monthly service retirement benefits which include any cost of living adjustments granted during the TERI period. Because participants are considered retired during the TERI period, they do not earn service credit or disability retirement benefits. Effective July 1, 2005, TERI employees began "re-contributing" to the SCRS at the prevailing rate. However, no service credit is earned under the new regulations. The group life insurance of one times annual salary was re-established for TERI participants.

Effective July 1, 2012, the TERI program closed for Class Two members (members with effective date prior to July 1, 2012) on June 30, 2018, and it is not available to Class Three members (members with effective date on or after July 1, 2012). TERI will be phased out in a 5-4-3-2-1 format. Members who enter the TERI program after July 1, 2013, will not be eligible to participate for the full five years. TERI participation will end on June 30, 2018, regardless of when a member enters the program.

Article X, Section 16 of the South Carolina Constitution requires that all State-operated retirement plans be funded on a sound actuarial basis. Title 9 of the South Carolina Code of Laws (as amended) prescribes requirements relating to membership, benefits and employee/employer contributions.

All employees are required by State statute to contribute to the SCRS at the prevailing rate, currently 8.00 percent. The Authority contributed 10.75 percent of the total payroll for SCRS retirement. For 2014, the Authority also contributed an additional 0.15 percent of total payroll for group life. The contribution requirements for the prior three years were as follows:

Years Ended December 31,	**2014**	2013	2012
		(Millions)	
From the Authority	**$ 13.9**	$ 13.3	$ 12.5
From Employees	**10.2**	9.2	8.5

The Authority made 100 percent of the required contributions for each of the three years.

The SCRS issues a stand-alone financial report that includes all required supplementary information. The report may be obtained by writing to: South Carolina Retirement System, P.O. Box 11960, Columbia, S.C. 29211.

Effective July 1, 2002, new employees have a choice of the type of retirement plan in which to enroll. The State Optional Retirement Plan (State ORP) which is a defined contribution plan is an alternative to the SCRS retirement plan which is a defined benefit plan. The contribution amounts are the same, (8.00 percent employee cost and 10.75 percent employer cost); however, 5.00 percent of the employer amount is directed to the vendor chosen by the employee and the remaining 5.75 percent is contributed to the Retirement System. As of December 31, 2014, the Authority had 42 employees participating in the State ORP and consequently the related payments are not material.

The Authority also provides retirement benefits to certain employees designated by management and the Board under supplemental executive retirement plans (SERP). Benefits are established and may be amended by management and the Authority's Board and includes retirement benefit payments for a specified number of years and death benefits. The cost of these benefits is actuarially determined annually. Beginning in 2006, these plans were segregated into internal and external funds. The qualified benefits are funded externally with the annual cost set aside in a trust administered by a third party. The pre-2006 retiree benefits and the non-qualified benefits are funded internally with the annual cost set aside and managed by the Authority. A summary of the Authority's SERP activity is as follows:

Years Ended December 31,	**2014**	2013
	(Millions)	
Total cost	**$ 1.3**	$ 1.1
Accrued liability	**$ 5.2**	$ 5.3

Summer Nuclear Retirement - The Authority and SCE&G are parties to a joint ownership agreement at the Summer Nuclear Station. As such, the Authority is responsible for funding its share of pension requirements for the nuclear station personnel. Any earnings generated from the established pension plan are shared proportionately and used to reduce the allocated funding.

As of December 31, 2014 and 2013, the Authority had over-funded its share of requirements by $766,000 and $910,000, respectively. This receivable however, is offset by a regulatory liability as required by FASB ASC 715. The balances were approximately $18.6 million and $15.0 million for the unfunded portion of pension benefits at December 31, 2014 and 2013, respectively. Additional information may be obtained by reference to the SCANA Corporation Annual Report on Form 10K as filed with the Securities Exchange Commission as of December 31, 2014.

NOTE 12 – OTHER POSTEMPLOYMENT BENEFITS (OPEB)

Vacation / Sick Leave – Full-time employees earn 10 days of vacation leave for service under five years and 15 days of vacation leave for service under 11 years. Employees earn an additional day of vacation leave for each year of service over 10 until they reach the maximum of 25 days per year. Employees earn two hours per pay period, plus 20 additional hours at year-end for sick leave.

Employees may accumulate up to 45 days of vacation leave and 180 days of sick leave. Upon termination, the Authority pays employees for unused vacation leave at the pay rate then in effect. In addition, the Authority pays employees upon retirement 20 percent of their sick leave at the pay rate then in effect.

Plan Description - The Authority participates in an agent multiple-employer defined benefit healthcare plan whereby PEBA provides certain health, dental and life insurance benefits for eligible retired employees of the Authority. The retirement benefits available are defined by PEBA and substantially all of the Authority's employees may become eligible for these benefits if they retire at any age with a minimum of 10 years of earned service or at age 60 with at least 20 years of service. Currently, approximately 792 retirees meet these requirements.

For employees hired May 2, 2008 or thereafter, the number of years of earned service necessary to qualify for funded retiree insurance is 15 years for a one-half contribution, and 25 years for a full contribution. PEBA may be contacted at: Retirement Benefits, PO Box 11660, Columbia, S.C. 29211-1960.

Funding Policy - Prior to 2010, the Authority used the unfunded pay-as-you-go option (or cash disbursement) method pursuant to GASB 45 to record the net OPEB obligations. During 2010, the Authority elected to adopt an advanced or pre-funding policy and established an irrevocable trust with Synovus Trust Company. This method of funding will eventually result in lower contributions over time compared to the prior pay-as-you-go funding policy.

Annual OPEB Cost - The Authority's annual OPEB cost is calculated based on the annual required contribution (ARC) of the employer, an amount actuarially determined in accordance with the parameters of GASB 45. The ARC represents a level of funding that is projected (if paid on an on-going basis) to recognize the normal cost each year and to amortize any unfunded actuarial liabilities (or funding excess) over a period not to exceed 30 years. The Authority's contribution towards ARC is equal to the actual disbursements during the year for health care benefits for retired employees plus annual funding amounts for the trust. The Authority's annual OPEB cost (expense) was as follows:

Year Ended December 31,		**2014**		2013
		(Thousands)		
Annual required contribution	**$**	**12,038**	$	11,687
Interest on OPEB obligation		**538**		513
Adjustment to ARC		**(464)**		(442)
Annual OPEB cost		**12,112**		11,758
Net estimated employer contributions		**(11,691)**		(11,302)
Increase in net OPEB obligation	**$**	**421**	$	456
Net OPEB obligation - beginning of year	**$**	**9,781**	$	9,325
Net OPEB obligation - end of year	**$**	**10,202**	$	9,781

The Authority's annual OPEB cost, the percentage of annual OPEB cost contributed to the plan, and the net OPEB obligation for fiscal year ending December 31, 2014 and the preceding two fiscal years were as follows:

	Annual OPEB Cost	**Employer Amount Contributed**	**Net OPEB Obligation**	**Percentage Contributed**
Years Ended December 31,		(Thousands)		(%)
2012	$ 10,261	$ 12,795	$ 9,325	124.7
2013	11,758	11,302	9,781	96.1
2014	**12,112**	**11,691**	**10,202**	**96.5**

Funded Status and Funding Progress - The funded status of the Authority's retiree health care plan under GASB 45 as of December 31, 2012, the latest actuarial study date, is as follows:

Required Supplementary Information - Schedule of Funding Progress

Actuarial Value of Assets (a)	**Actuarial Accrued Liability (AAL) (b)**	**Annual Covered Payroll (c)**	**Unfunded AAL (UAAL) (b) - (a)**	**Funded Ratio (a / b)**	**Ratios of UAAL to Annual Covered Payroll (b-a)/(c)**
	(Thousands)				(%)
$ 27,829	**$ 170,040**	**$ 113,683**	**$ 142,211**	**16.4**	**125.1**

Note: As of December 31, 2014, the OPEB trust had assets of $39.4 million.

The required schedule of funding progress presented as required supplementary information provided multi-year trend information that shows whether the actuarial value of plan assets is increasing over time relative to the actuarial accrued liability for benefits.

Actuarial Methods and Assumptions - The Projected Unit Credit actuarial cost method is used to calculate the GASB ARC for the Authority's retiree health care plan. Using the plan benefits, the present health premiums and a set of actuarial assumptions, the anticipated future payments are projected. The projected unit credit method then provides for a systematic recognition of the cost of these anticipated payments. The yearly ARC is computed to cover the cost of benefits being earned by covered members, as well as to amortize a portion of the unfunded accrued liability.

Actuarial valuations involve estimates of the value of reported amounts and assumptions about the probability of events in the future. Amounts determined regarding the funded status and the annual required contributions of the Authority's retiree health care plan are subject to continual revision as actual results are compared to past expectations and new estimates are made about the future.

Projections of health benefits are based on the plan as understood by the Authority and include the types of benefits in force at the valuation date and the pattern of sharing benefit costs between the Authority and its employees to that point. Actuarial calculations reflect a long-term perspective and employ methods and assumptions that are designed to reduce short-term volatility in actuarial accrued liabilities and the actuarial value of assets. Significant methods and assumptions were as follows:

Actuarial Methods and Assumptions	
Inflation rate	3.00% per annum
Investment rate of return	5.50% net of expenses
Actuarial cost method	Projected Unit Credit Cost Method
Amortization method	Level as a percentage of employee payroll
Amortization period	30 year, open amortization
Payroll growth	3.00% per annum
Medical trend:	
Initial	7.00%
Ultimate	4.50% after 10 years
Drug trend:	
Initial	7.25%
Ultimate	4.50% after 10 years

Summer Nuclear OPEB - The Authority is responsible for funding its share of OPEB costs for nuclear station employees. The Authority's liability balances as of December 31, 2014 and 2013 were approximately $10.5 million and $10.1 million, respectively.

In accordance with FASB ASC 715, the Authority recorded a regulatory liability of approximately $4.6 million and $2.6 million for the unfunded portion of OPEB costs at December 31, 2014 and 2013, respectively. Additional information may be obtained by reference to the SCANA Corporation Annual Report on Form 10K as filed with the Securities Exchange Commission as of December 31, 2014.

NOTE 13 - CREDIT RISK AND MAJOR CUSTOMERS

In 2014, the Authority had one customer that accounted for more than 10 percent of the Authority's sales:

Customer:	**2014**	2013
	(Millions)	
Central	**$ 1,118**	$ 1,038

The Authority maintains an allowance for uncollectible accounts based upon the expected collectability of all accounts receivable. The allowance at each year ended December 31, 2014 and 2013 was $1.6 million and $1.3 million, respectively.

NOTE 14 – STORM DAMAGE

In February 2014, the Authority's system sustained damages from Winter Storm Pax (Pax). As a result, several counties in South Carolina were designated as a federal disaster area. The damage sustained by the Authority in these counties was mainly to the Authority's transmission and distribution systems.

As of December 31, 2014, all the restoration and repair work had been completed and/or accrued to capital cost or maintenance expense. The Authority received disaster relief assistance from federal sources on all eligible costs from the storm as of the close of 2014. The damages to the distribution system resulted in capital restoration costs of $1.9 million and federal reimbursement of $1.3 million. Damages to the transmission system resulted in maintenance expense and capital costs of approximately $761,000 and $632,000, respectively. The Authority received federal reimbursement of approximately $832,000.

The Authority does not expect to increase rates due to the impact of Pax and foresees no measurable long-term impact on its operations or the demand for electricity by its customers.

NOTE 15 - SUBSEQUENT EVENT(S)

We have evaluated subsequent events through February 19, 2015 in conjunction with the preparation of these financial statements which is the date the financial statements were available to be issued. As of this date, the Authority has no subsequent events to report.

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BOARD OF DIRECTORS

W. Leighton Lord III
Chairman
Columbia, S.C.

Director Lord is a partner in Nexsen Pruet law firm in Columbia.

William A. Finn
1st Vice Chairman
1st Congressional District
Charleston, S.C.

Director Finn is chairman of AstenJohnson Inc., a specialty textile company for the printing and papermaking industries based in Charleston.

Barry D. Wynn
2nd Vice Chairman
4th Congressional District
Spartanburg, S.C.

Director Wynn is president of Colonial Trust Company, a private trust company specializing in investment management and estate services.

Kristofer D. Clark
3rd Congressional District
Easley, S.C.

Director Clark is owner of Pristine Properties LLC and a broker at Easlan Capital.

Merrell W. Floyd
7th Congressional District
Conway, S.C.

Director Floyd retired in 2005 as staff coordinator at Horry Electric Cooperative.

Catherine E. Heigel
At-Large
Greenville, S.C.

Director Heigel is the general counsel and corporate strategies officer with Elliott Davis LLC, a full-service accounting, tax, and business advisory firm.

J. Calhoun Land IV
6th Congressional District
Manning, S.C.

Director Land is a partner in Land, Parker & Welch, a general practice law firm in Manning.

Peggy H. Pinnell
Berkeley County
Moncks Corner, S.C.

Director Pinnell is the owner of the Peggy H. Pinnell Insurance Agency, a State Farm agency in Moncks Corner.

Dan J. Ray
Georgetown County
Pawleys Island, S.C.

Director Ray is a managing director and the global head of project finance for Jefferies LLC.

David F. Singleton
Horry County
Myrtle Beach, S.C.

Director Singleton is president of Singleton Properties, a real estate investment and sales firm.

Jack F. Wolfe Jr.
2nd Congressional District
Chapin, S.C.

Director Wolfe is a past president and CEO of the Mid-Carolina Electric Cooperative in Lexington, S.C.

Notes:
Director Cecil E. Viverette's term expired effective May 1, 2014.

The South Carolina Senate on May 1, 2014, confirmed Directors Merrell W. Floyd, Catherine E. Heigel, Dan J. Ray and Jack F. Wolfe Jr. to the Santee Cooper Board of Directors and reappointed Directors Kristofer D. Clark and J. Calhoun Land IV.

The 5th Congressional District seat is vacant.

Advisory Board

Nikki Haley
Governor

Alan Wilson
Attorney General

Mark Hammond
Secretary of State

Richard Eckstrom
Comptroller General

Curtis M. Loftis Jr.
State Treasurer

Executive Leadership

Lonnie N. Carter	*President and Chief Executive Officer*
Jeffrey D. Armfield	*Senior Vice President and Chief Financial Officer*
J. Michael Baxley(1)	*Senior Vice President and General Counsel*
Michael R. Crosby(2)	*Senior Vice President, Nuclear Energy*
Robert B. Fleming Jr.	*Senior Vice President, Power Delivery*
L. Phil Pierce	*Senior Vice President, Generation*
Marc R. Tye	*Senior Vice President, Customer Service*
Pamela J. Williams(3)	*Senior Vice President, Corporate Services*

Management

S. Thomas Abrams	*Vice President, Planning and Power Supply*
Michael C. Brown	*Vice President, Wholesale and Industrial Services*
Glenda W. Gillette	*Vice President and Controller*
Jane H. Hood	*Vice President, Fuels Strategy and Supply*
Thomas L. Kierspe	*Vice President, Environmental, Property and Water Systems Management*
Richard S. Kizer	*Vice President, Public Affairs*
J. Michael Poston	*Vice President, Retail Operations*
Suzanne H. Ritter	*Treasurer and Vice President, Corporate Planning*
Arnold R. Singleton(4)	*Vice President, Administration*
Laura G. Varn	*Vice President, Human Resource Management*
Elizabeth H. Warner	*Vice President, Legal Services and Corporate Secretary*

Auditor

Kenneth W. Lott III	*General Auditor*

(1) J. Michael Baxley was named Senior Vice President and General Counsel effective July 1, 2014.
(2) Michael R. Crosby was named Senior Vice President, Nuclear Energy effective May 1, 2014.
(3) Pamela J. Williams was named Senior Vice President, Corporate Services effective May 1, 2014.
(4) Arnold R. Singleton was named Vice President, Administration effective May 5, 2014.

OFFICE LOCATIONS

CAROLINA FOREST TOWN CENTRE OFFICE
3990 River Oaks Drive
Myrtle Beach, SC 29579
843-946-5950
843-903-1333 Fax

CONWAY OFFICE
100 Elm Street
Conway, SC 29526
843-248-5755
843-248-7315 Fax

LORIS OFFICE
3701 Walnut Street
Loris, SC 29569
843-756-5541
843-756-7008 Fax

MONCKS CORNER OFFICE SANTEE COOPER HEADQUARTERS
One Riverwood Drive
Moncks Corner, SC 29461
843-761-8000
843-761-4122 Fax

MYRTLE BEACH OFFICE
1703 Oak Street
Myrtle Beach, SC 29577
843-448-2411
843-626-1923 Fax

MURRELLS INLET/GARDEN CITY OFFICE
900 Inlet Square Drive
Murrells Inlet, SC 29576
843-651-1598
843-651-7889 Fax

NORTH MYRTLE BEACH OFFICE
1000 2nd Avenue North
North Myrtle Beach, SC 29582
843-249-3505
843-249-6843 Fax

PAWLEYS ISLAND OFFICE
126 Tiller Road
Pawleys Island, SC 29585
843-237-9222
843-237-8959 Fax

ST. STEPHEN OFFICE
1172 Main Street
St. Stephen, SC 29479
843-567-3346
843-567-4709 Fax