NEW ISSUE -- Book Entry

In the opinion of Bond Counsel, assuming continued compliance by the Authority with certain covenants, interest on the 2014M1 Bonds is excludable from gross income for federal income tax purposes under existing statutes, regulations and judicial decisions. Interest on the 2014M1 Bonds is not an item of tax preference in computing the alternative minimum taxable income of individuals or corporations. Interest on the 2014M1 Bonds will, however, be included in the computation of certain taxes including alternative minimum tax for corporations. See "TAX MATTERS" for a description of certain other federal income tax consequences to certain recipients of interest on the 2014M1 Bonds. The 2014M1 Bonds and the interest thereon will be exempt from all State, county, municipal and school district and other taxes or assessments imposed within the State of South Carolina, except estate, transfer and certain franchise taxes.

$39,584,800
South Carolina Public Service Authority

santee cooper

Revenue Obligations, 2014 Series M1
Consisting of

$4,263,000 1.75% Current Interest Bearing Bonds Due January 1, 2019
$4,034,500 3.00% Current Interest Bearing Bonds Due January 1, 2024
$6,881,500 4.00% Current Interest Bearing Bonds Due January 1, 2029
$17,214,000 4.30% Current Interest Bearing Bonds Due January 1, 2034
$2,570,200 3.00% Capital Appreciation Bonds Due January 1, 2023
$2,027,800 4.00% Capital Appreciation Bonds Due January 1, 2028
$2,593,800 4.30% Capital Appreciation Bonds Due January 1, 2033

Dated: May 1, 2014

The Revenue Obligations, 2014 Series M1 (the "2014M1 Bonds") will be sold directly by the South Carolina Public Service Authority (the "Authority") only to residents of the State of South Carolina (the "State"), customers of the Authority, members of electric cooperatives organized and existing under the laws of the State, and electric customers of the Bamberg Board of Public Works, South Carolina and the City of Georgetown, South Carolina.

The Current Interest Bearing Bonds will be issued in registered form in denominations of $500 or integral multiples thereof. The Capital Appreciation Bonds will be issued in registered form in denominations of $200 original principal amount or integral multiples thereof. The 2014M1 Bonds will be sold by the Authority directly to investors. The maximum amount of 2014M1 Bonds, as measured by the initial purchase price thereof, which may be initially purchased by one investor shall be $50,000 as described herein. Any 2014M1 Bonds will be purchased by the Authority on demand by the owner thereof upon the terms and conditions set forth herein. The Authority's obligation to redeem the 2014M1 Bonds at the election of the Bondholders is limited to 5% of the original issue amount of the 2014M1 Bonds in any calendar year. Redemptions will also be limited on a monthly basis to one-twelfth of the 5% annual maximum. Interest on the Current Interest Bearing Bonds, payable on January 1 and July 1 of each year, commencing January 1, 2015 (240 days of interest), interest on the Capital Appreciation Bonds (compounded semiannually and payable only upon maturity or earlier redemption or elective purchase thereof), maturing principal of the Current Interest Bearing Bonds and maturing principal of the Capital Appreciation Bonds will be payable by check or draft mailed to the registered owners thereof by The Bank of New York Mellon Trust Company, N.A. (the "Trustee").

The 2014M1 Bonds will be subject to redemption prior to maturity at the option of the Authority on and after January 1, 2015, as set forth herein.

The 2014M1 Bonds are payable solely from, and secured by a lien upon and pledge of, the Revenues and moneys in the Revenue Fund of the Authority on a parity with the lien and pledge securing Revenue Obligations heretofore and hereafter issued pursuant to the Revenue Obligation Resolution.

The 2014M1 Bonds are being issued to fund a portion of the cost of the Authority's ongoing capital improvement program.

The 2014M1 Bonds are not debts of the State, nor of any political subdivision thereof, and neither the State nor any of its political subdivisions shall be liable thereon, nor shall they be payable from any funds other than the Revenues of the Authority pledged to the payment thereof.

The 2014M1 Bonds are offered when, as and if issued subject to the approval of legality by Haynsworth Sinkler Boyd, P.A., Charleston, South Carolina, Bond Counsel.

May 15, 2014

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SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
One Riverwood Drive
Moncks Corner, South Carolina 29461
(843) 761-8000

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Attorney General ALAN WILSON

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The Bank of New York Mellon Trust Company, N.A. — Jacksonville, Florida

BOND COUNSEL

Haynsworth Sinkler Boyd, P.A. — Charleston, South Carolina

FINANCIAL ADVISOR

Public Financial Management, Inc. — Charlotte, North Carolina

No dealer, broker, salesman or other person has been authorized by the Authority or the Underwriter to give any information or to make any representations with respect to the 2014M1 Bonds other than the information and representations contained in this Official Statement, and, if given or made, such other information or representations may not be relied upon as having been authorized by the Authority. This Official Statement does not constitute an offer to sell or the solicitation of an offer to buy nor shall there be any sale of the 2014M1 Bonds by any person in any jurisdiction in which it is unlawful for such person to make such offer, solicitation or sale. The information set forth herein has been provided by the Authority and other sources which are believed to be reliable. The information and expressions of opinion herein are subject to change without notice and neither the delivery of this Official Statement nor any sale made hereunder shall, under any circumstances, create any implication that there has been no change in the matters described herein since the date hereof.

NEITHER THE SECURITIES AND EXCHANGE COMMISSION NOR ANY STATE SECURITIES COMMISSION HAS APPROVED OR DISAPPROVED OF THE 2014M1 BONDS OR PASSED UPON THE ADEQUACY OR ACCURACY OF THIS OFFICIAL STATEMENT. ANY REPRESENTATION TO THE CONTRARY IS A CRIMINAL OFFENSE.

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OFFICIAL STATEMENT
relating to
$39,584,800
South Carolina Public Service Authority
Revenue Obligations, 2014 Series M1

$4,263,000 1.75% Current Interest Bearing Bonds Due January 1, 2019
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INTRODUCTION

General

The purpose of this Official Statement is to set forth information concerning the South Carolina Public Service Authority (the "Authority") Revenue Obligations, 2014 Series M1 (the "2014M1 Bonds"), offered hereby.

The summary of the Revenue Obligation Resolution (hereinafter defined) herein contained is made subject to all of the provisions of such document, and such summary does not purport to be complete statements of such provisions. Reference is hereby made to such document for further information in connection therewith. Copies of such document may be examined at the main office of the Authority in Moncks Corner, South Carolina, and at the office of Haynsworth Sinkler Boyd, P.A., Charleston, South Carolina. The REPORT OF THE COMPANY'S FINANCIAL STATEMENTS is attached as Appendix I to this Official Statement.

Defined terms not herein defined are defined in Appendix II -- "SUMMARY OF CERTAIN PROVISIONS OF THE REVENUE OBLIGATION RESOLUTION."

The Authority

The Authority is a body corporate and politic created by Act No. 887 of the Acts of the State of South Carolina (the "State") for 1934 and acts supplemental thereto and amendatory thereof (Code of Laws of South Carolina 1976, as amended -- Sections 58-31-10 through 58-31-450) (the "Act"), which, among other things, authorizes the Authority to produce, distribute and sell electric power and to acquire, treat, transmit, distribute and sell water at wholesale within the counties of Berkeley, Calhoun, Charleston, Clarendon, Colleton, Dorchester, Orangeburg and Sumter, South Carolina. The Authority owns and operates the Lake Moultrie Regional Water System and the Lake Marion Regional Water System. Under current State law and by contract, each of the regional water systems is required to be self supporting. The Authority began electric power operations in 1942. The commercial operation of the regional water system began in October 1994.

Authorization of 2014M1 Bonds

The 2014M1 Bonds are issued pursuant to a resolution adopted by the Authority's Board of Directors on April 26, 1999, as amended and supplemented from time to time (the "Revenue Obligation Resolution"). The 2014M1 Bonds now being offered and all obligations heretofore and hereafter issued pursuant to the Revenue Obligation Resolution (collectively, the "Revenue Obligations") are on a parity with each other. The Revenue Obligations are secured by a lien upon and pledge of the Revenue Fund and the revenues of the Authority's System and other moneys paid into the Revenue Fund (the "Revenues"). See "SECURITY FOR THE 2014M1 BONDS." By supplemental resolution duly adopted, the Authority authorized the issuance of the 2014M1 Bonds.

Indebtedness of the Authority

Revenue Obligations. Pursuant to the Act, the Board of Directors of the Authority adopted the Revenue Obligation Resolution providing for the issuance of the Authority's Revenue Obligations. As of March 31, 2014 there was outstanding approximately $6,308,730,000 aggregate principal amount of Revenue Obligations.

Commercial Paper Notes and Leases. In addition, the Authority has issued indebtedness evidenced by commercial paper notes (the "Commercial Paper Notes") and leases. As of March 31, 2014 there was outstanding $372,073,000 of Commercial Paper Notes and approximately $156,000 aggregate amount of leases. The lien and pledge of Revenues securing such Commercial Paper Notes and leases is junior to that securing the Revenue Obligations.

The Board of Directors of the Authority has by resolution authorized the issuance of Commercial Paper Notes not to exceed the lesser of (i) 20% of the aggregate Authority debt outstanding as of the last day of the most recent fiscal year for which audited financial statements of the Authority are available or (ii) the aggregate unused commitment of the Banks (hereinafter defined) (i.e., the commitment minus any loans outstanding under the revolving credit agreements) under any revolving credit agreements the Authority may enter into to obtain funds to repay the Commercial Paper Notes. The Commercial Paper Notes are secured by a lien upon and pledge of Revenues junior to the lien and pledge securing (i) Revenue Obligations, (ii) expenses of operating and maintaining the System, and (iii) payments into the Lease Fund, but prior to the payments into the Capital Improvement Fund.

To obtain funds, if needed to repay the Commercial Paper Notes, the Authority has entered into Revolving Credit Agreements (the "Revolving Credit Agreements") with U.S. Bank National Association, Wells Fargo Bank, National Association, JP Morgan Chase Bank, National Association, TD Bank, N.A. and Barclays Bank PLC (collectively, the "Banks") for an aggregate amount of $800,000,000. The agreement with U.S. Bank National Association allows the Authority to borrow up to $100,000,000 and expires on December 31, 2014. The agreement with JP Morgan Chase Bank, National Association allows the Authority to borrow up to $250,000,000 and expires on September 15, 2014. The agreement with Wells Fargo Bank, National Association allows the Authority to borrow up to $150,000,000 and expires on September 15, 2014. The agreement with TD Bank, N.A. allows the Authority to borrow up to $100,000,000 and expires on November 27, 2015. The agreement with Barclays Bank PLC allows the Authority to borrow up to $200,000,000 and expires on November 27, 2015.

The Authority's obligation to repay any such loans is secured by a lien upon and pledge of Revenues *pari passu* with the lien upon and pledge of Revenues securing the Commercial Paper Notes. No loans are outstanding under the Revolving Credit Agreements.

Purpose of the 2014M1 Bonds

The 2014M1 Bonds are being issued to fund a portion of the cost of the Authority's ongoing capital improvement program. See "CAPITAL IMPROVEMENT PROGRAM."

DESCRIPTION OF THE CURRENT INTEREST BEARING BONDS

General

The Current Interest Bearing Bonds will be dated May 1, 2014 and will mature on January 1, 2019 at the interest rate of 1.75%, on January 1, 2024 at the interest rate of 3.00%, on January 1, 2029 at the interest rate of 4.00%, and on January 1, 2034 at the interest rate of 4.30%. The Current Interest Bearing Bonds will be issued as registered bonds without coupons in the denominations of five hundred ($500) dollars or any integral multiple thereof and when issued will initially be in book-entry form. See "DESCRIPTION OF BOOK-ENTRY ONLY SYSTEM." Interest on the Current Interest Bearing Bonds, payable semiannually on each January 1 and July 1 commencing January 1, 2015 (at which time 240 days of interest will be due), and maturing principal of the Current Interest Bearing Bonds will be payable by check or draft mailed by The Bank of New York Mellon Trust Company, N.A., as Trustee, to the registered owners thereof as shown on the registration books on the fifteenth day of the month prior to each payment date. The total combined order of the Current Interest Bearing Bonds and Capital Appreciation Bonds, as measured by the initial purchase price thereof per series, which may be initially purchased by any one investor shall be $50,000. The Current Interest Bearing Bonds may be transferred to another owner but only on the registration books of the Authority held by the Trustee, as registrar.

Redemption

The Current Interest Bearing Bonds shall be subject to redemption prior to maturity at the option of the Authority on and after January 1, 2015, upon not less than 30 days written notice, as a whole at any time, or in part from time to time on any interest payment date (and, in the event that less than all of the Current Interest Bearing Bonds are called for redemption, the particular Current Interest Bearing Bonds or portions thereof to be redeemed shall be selected by lot by the Trustee, but only in integral multiples of $500 denominations), at the redemption price of 100% of the principal amount of each Current Interest Bearing Bond to be redeemed, together with the interest accrued thereon to the date fixed for redemption.

Purchase of Current Interest Bearing Bonds by Authority

On or after January 1, 2015 any Current Interest Bearing Bond (or portion thereof in authorized denomination) will be purchased by the Authority, on the demand of the registered owner thereof, on the first day (or, if such day is not a business day, on the next succeeding business day) of the first or second month next succeeding the date of delivery of the written notice to the Authority at a purchase price equal to the principal amount thereof less a fee of $15 per $500 principal amount to be purchased, together with accrued interest to the purchase date, upon delivery to the Authority, of not less than 30 days written notice, properly endorsed with signature guaranteed, which states (i) the CUSIP number, face amount, maturity date and series designation of the Current Interest Bearing Bond to be purchased, and (ii) the portion of the principal amount of such Current Interest Bearing Bond to be purchased (provided that such portion shall be an integral multiple of $500).

The Authority's obligation to purchase 2014M1 Bonds tendered for purchase is limited to 5% of the original issue amount of the 2014M1 Bonds in any calendar year. Purchases will also be limited on a monthly basis to one-twelfth of the 5% annual maximum. Purchases will be processed in the order of receipt by the Authority of tenders for purchase.

DESCRIPTION OF THE CAPITAL APPRECIATION BONDS

General

The Capital Appreciation Bonds will be dated May 1, 2014 and will mature on January 1, 2023 at the interest rate of 3.00%, on January 1, 2028 at the interest rate of 4.00% and on January 1, 2033 at the interest rate of 4.30%. The Capital Appreciation Bonds are payable in an amount (the "Accreted Value") equal to the principal amount of such Capital Appreciation Bonds plus interest from the date of such Capital Appreciation Bonds, compounded on January 1 and July 1 of each year. The Capital Appreciation Bonds will be issued as registered bonds without coupons in the denominations of two hundred ($200) dollars or any integral multiple thereof and when issued will initially be in book-entry form. See "DESCRIPTION OF BOOK-ENTRY ONLY SYSTEM." The Capital Appreciation Bonds will bear interest on the original principal amounts thereof, compounded semiannually on January 1 and July 1 of each year commencing January 1, 2015, and payable only upon maturity or earlier redemption or elective purchase thereof. The maturing Accreted Value of the Capital Appreciation Bonds and Current Interest Bearing Bonds, as measured by the initial purchase price thereof per series, which may be initially purchased by any one investor shall be $50,000. The Capital Appreciation Bonds may be transferred to another owner but only on the registration books of the Authority held by the Trustee, as registrar.

Redemption

The Capital Appreciation Bonds shall be subject to redemption prior to maturity at the option of the Authority on and after January 1, 2015, upon not less than 30 days written notice, as a whole at any time, or in part from time to time on any January 1 or July 1 (and, in the event that less than all of the Capital Appreciation Bonds are called for redemption, the particular Capital Appreciation Bonds or portions thereof to be redeemed shall be selected by lot by the Trustee, but only in integral multiples of $200 denominations), at a redemption price equal to the Accreted Value on the redemption date of any such Capital Appreciation Bond to be redeemed.

Purchase of Capital Appreciation Bonds by Authority

On or after January 1, 2015 any Capital Appreciation Bond (or portion thereof in authorized denomination) will be purchased by the Authority, on the demand of the registered owner thereof, on the first day (or, if such day is not a business day, on the next succeeding business day) of the first or second month next succeeding the date of delivery of the written notice to the Authority at 100% of the Accreted Value thereof on the date of purchase less a fee of $6.00 per $200 original principal amount to be purchased, upon delivery to the Authority, of not less than 30 days written notice, properly endorsed with signature guaranteed, which states (i) the CUSIP number, original principal amount, maturity date and series designation of the Capital Appreciation Bond to be purchased, and (ii) the portion of the original principal amount of such Capital Appreciation Bond to be purchased (provided that such portion shall be an integral multiple of $200).

The Authority's obligation to purchase 2014M1 Bonds tendered for purchase is limited to 5% of the original issue amount of the 2014M1 Bonds in any calendar year. Purchases will also be limited on a monthly basis to one-twelfth of the 5% annual maximum. Purchases will be processed in the order of receipt by the Authority of tenders for purchase.

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Accreted Value Table for Capital Appreciation Bonds Maturity January 1, 2023

The Accreted Value amount due at optional redemption, elective purchase or maturity of each $200 original principal amount of any Capital Appreciation Bond with a maturity date of January 1, 2023, as of the first day of each month to maturity will be set forth below. The Accreted Value of each $200 original principal amount of any Capital Appreciation Bond on any other date will be calculated on the assumption that such Accreted Value increases in equal daily amounts on the basis of twelve 30-day months.

Date	Accreted Value	Date	Accreted Value	Date	Accreted Value
Jan. 1, 2015	$204.02	Jul. 1, 2018	$226.43	Jan. 1, 2022	$251.30
Feb. 1, 2015	204.52	Aug. 1, 2018	226.99	Feb. 1, 2022	251.92
Mar. 1, 2015	205.03	Sep. 1, 2018	227.55	Mar. 1, 2022	252.55
Apr. 1, 2015	205.54	Oct. 1, 2018	228.12	Apr. 1, 2022	253.17
May 1, 2015	206.05	Nov. 1, 2018	228.68	May 1, 2022	253.80
Jun. 1, 2015	206.56	Dec. 1, 2018	229.25	Jun. 1, 2022	254.43
Jul. 1, 2015	207.08	Jan. 1, 2019	229.82	Jul. 1, 2022	255.07
Aug. 1, 2015	207.59	Feb. 1, 2019	230.39	Aug. 1, 2022	255.70
Sep. 1, 2015	208.11	Mar. 1, 2019	230.96	Sep. 1, 2022	256.34
Oct. 1, 2015	208.62	Apr. 1, 2019	231.54	Oct. 1, 2022	256.97
Nov. 1, 2015	209.14	May 1, 2019	232.11	Nov. 1, 2022	257.61
Dec. 1, 2015	209.66	Jun. 1, 2019	232.69	Dec. 1, 2022	258.25
Jan. 1, 2016	210.18	Jul. 1, 2019	233.27	Jan. 1, 2023	258.89
Feb. 1, 2016	210.70	Aug. 1, 2019	233.85		
Mar. 1, 2016	211.23	Sep. 1, 2019	234.43		
Apr. 1, 2016	211.75	Oct. 1, 2019	235.01		
May 1, 2016	212.28	Nov. 1, 2019	235.60		
Jun. 1, 2016	212.81	Dec. 1, 2019	236.18		
Jul. 1, 2016	213.33	Jan. 1, 2020	236.77		
Aug. 1, 2016	213.86	Feb. 1, 2020	237.36		
Sep. 1, 2016	214.40	Mar. 1, 2020	237.95		
Oct. 1, 2016	214.93	Apr. 1, 2020	238.54		
Nov. 1, 2016	215.46	May 1, 2020	239.13		
Dec. 1, 2016	216.00	Jun. 1, 2020	239.72		
Jan. 1, 2017	216.53	Jul. 1, 2020	240.32		
Feb. 1, 2017	217.07	Aug. 1, 2020	240.92		
Mar. 1, 2017	217.61	Sep. 1, 2020	241.51		
Apr. 1, 2017	218.15	Oct. 1, 2020	242.11		
May 1, 2017	218.69	Nov. 1, 2020	242.72		
Jun. 1, 2017	219.24	Dec. 1, 2020	243.32		
Jul. 1, 2017	219.78	Jan. 1, 2021	243.92		
Aug. 1, 2017	220.33	Feb. 1, 2021	244.53		
Sep. 1, 2017	220.88	Mar. 1, 2021	245.14		
Oct. 1, 2017	221.42	Apr. 1, 2021	245.75		
Nov. 1, 2017	221.97	May 1, 2021	246.36		
Dec. 1, 2017	222.53	Jun. 1, 2021	246.97		
Jan. 1, 2018	223.08	Jul. 1, 2021	247.58		
Feb. 1, 2018	223.63	Aug. 1, 2021	248.20		
Mar. 1, 2018	224.19	Sep. 1, 2021	248.81		
Apr. 1, 2018	224.75	Oct. 1, 2021	249.43		
May 1, 2018	225.30	Nov. 1, 2021	250.05		
Jun. 1, 2018	225.86	Dec. 1, 2021	250.67		

Accreted Value Table for Capital Appreciation Bonds Maturity January 1, 2028

The Accreted Value amount due at optional redemption, elective purchase or maturity of each $200 original principal amount of any Capital Appreciation Bond with a maturity date of January 1, 2028, as of the first day of each month to maturity will be set forth below. The Accreted Value of each $200 original principal amount of any Capital Appreciation Bond on any other date will be calculated on the assumption that such Accreted Value increases in equal daily amounts on the basis of twelve 30-day months.

Date	Accreted Value	Date	Accreted Value	Date	Accreted Value
Jan. 1, 2015	$205.36	Jul. 1, 2018	$235.89	Jan. 1, 2022	$270.97
Feb. 1, 2015	206.04	Aug. 1, 2018	236.67	Feb. 1, 2022	271.86
Mar. 1, 2015	206.72	Sep. 1, 2018	237.46	Mar. 1, 2022	272.76
Apr. 1, 2015	207.40	Oct. 1, 2018	238.24	Apr. 1, 2022	273.66
May 1, 2015	208.09	Nov. 1, 2018	239.03	May 1, 2022	274.57
Jun. 1, 2015	208.78	Dec. 1, 2018	239.82	Jun. 1, 2022	275.48
Jul. 1, 2015	209.47	Jan. 1, 2019	240.61	Jul. 1, 2022	276.39
Aug. 1, 2015	210.16	Feb. 1, 2019	241.41	Aug. 1, 2022	277.30
Sep. 1, 2015	210.85	Mar. 1, 2019	242.21	Sep. 1, 2022	278.22
Oct. 1, 2015	211.55	Apr. 1, 2019	243.01	Oct. 1, 2022	279.14
Nov. 1, 2015	212.25	May 1, 2019	243.81	Nov. 1, 2022	280.06
Dec. 1, 2015	212.95	Jun. 1, 2019	244.62	Dec. 1, 2022	280.99
Jan. 1, 2016	213.66	Jul. 1, 2019	245.42	Jan. 1, 2023	281.92
Feb. 1, 2016	214.36	Aug. 1, 2019	246.24	Feb. 1, 2023	282.85
Mar. 1, 2016	215.07	Sep. 1, 2019	247.05	Mar. 1, 2023	283.78
Apr. 1, 2016	215.78	Oct. 1, 2019	247.87	Apr. 1, 2023	284.72
May 1, 2016	216.50	Nov. 1, 2019	248.69	May 1, 2023	285.66
Jun. 1, 2016	217.21	Dec. 1, 2019	249.51	Jun. 1, 2023	286.61
Jul. 1, 2016	217.93	Jan. 1, 2020	250.33	Jul. 1, 2023	287.55
Aug. 1, 2016	218.65	Feb. 1, 2020	251.16	Aug. 1, 2023	288.50
Sep. 1, 2016	219.37	Mar. 1, 2020	251.99	Sep. 1, 2023	289.46
Oct. 1, 2016	220.10	Apr. 1, 2020	252.82	Oct. 1, 2023	290.41
Nov. 1, 2016	220.83	May 1, 2020	253.66	Nov. 1, 2023	291.37
Dec. 1, 2016	221.56	Jun. 1, 2020	254.50	Dec. 1, 2023	292.34
Jan. 1, 2017	222.29	Jul. 1, 2020	255.34	Jan. 1, 2024	293.30
Feb. 1, 2017	223.02	Aug. 1, 2020	256.18	Feb. 1, 2024	294.27
Mar. 1, 2017	223.76	Sep. 1, 2020	257.03	Mar. 1, 2024	295.25
Apr. 1, 2017	224.50	Oct. 1, 2020	257.88	Apr. 1, 2024	296.22
May 1, 2017	225.24	Nov. 1, 2020	258.73	May 1, 2024	297.20
Jun. 1, 2017	225.99	Dec. 1, 2020	259.59	Jun. 1, 2024	298.18
Jul. 1, 2017	226.73	Jan. 1, 2021	260.45	Jul. 1, 2024	299.17
Aug. 1, 2017	227.48	Feb. 1, 2021	261.31	Aug. 1, 2024	300.16
Sep. 1, 2017	228.24	Mar. 1, 2021	262.17	Sep. 1, 2024	301.15
Oct. 1, 2017	228.99	Apr. 1, 2021	263.04	Oct. 1, 2024	302.15
Nov. 1, 2017	229.75	May 1, 2021	263.91	Nov. 1, 2024	303.15
Dec. 1, 2017	230.51	Jun. 1, 2021	264.78	Dec. 1, 2024	304.15
Jan. 1, 2018	231.27	Jul. 1, 2021	265.66	Jan. 1, 2025	305.15
Feb. 1, 2018	232.03	Aug. 1, 2021	266.53	Feb. 1, 2025	306.16
Mar. 1, 2018	232.80	Sep. 1, 2021	267.41	Mar. 1, 2025	307.18
Apr. 1, 2018	233.57	Oct. 1, 2021	268.30	Apr. 1, 2025	308.19
May 1, 2018	234.34	Nov. 1, 2021	269.19	May 1, 2025	309.21
Jun. 1, 2018	235.12	Dec. 1, 2021	270.08	Jun. 1, 2025	310.23

Date	Accreted Value	Date	Accreted Value	Date	Accreted Value
Jul. 1, 2025	$311.26	Oct. 1, 2026	$327.05	Jan. 1, 2028	$343.65
Aug. 1, 2025	312.29	Nov. 1, 2026	328.14		
Sep. 1, 2025	313.32	Dec. 1, 2026	329.22		
Oct. 1, 2025	314.35	Jan. 1, 2027	330.31		
Nov. 1, 2025	315.39	Feb. 1, 2027	331.40		
Dec. 1, 2025	316.44	Mar. 1, 2027	332.50		
Jan. 1, 2026	317.48	Apr. 1, 2027	333.60		
Feb. 1, 2026	318.53	May 1, 2027	334.70		
Mar. 1, 2026	319.58	Jun. 1, 2027	335.80		
Apr. 1, 2026	320.64	Jul. 1, 2027	336.91		
May 1, 2026	321.70	Aug. 1, 2027	338.03		
Jun. 1, 2026	322.77	Sep. 1, 2027	339.15		
Jul. 1, 2026	323.83	Oct. 1, 2027	340.27		
Aug. 1, 2026	324.90	Nov. 1, 2027	341.39		
Sep. 1, 2026	325.98	Dec. 1, 2027	342.52		

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Accreted Value Table for Capital Appreciation Bonds Maturity January 1, 2033

The Accreted Value amount due at optional redemption, elective purchase or maturity of each $200 original principal amount of any Capital Appreciation Bond with a maturity date of January 1, 2033, as of the first day of each month to maturity will be set forth below. The Accreted Value of each $200 original principal amount of any Capital Appreciation Bond on any other date will be calculated on the assumption that such Accreted Value increases in equal daily amounts on the basis of twelve 30-day months.

Date	Accreted Value	Date	Accreted Value	Date	Accreted Value
Jan. 1, 2015	$205.76	Jul. 1, 2018	$238.80	Jan. 1, 2022	$277.14
Feb. 1, 2015	206.49	Aug. 1, 2018	239.65	Feb. 1, 2022	278.13
Mar. 1, 2015	207.23	Sep. 1, 2018	240.50	Mar. 1, 2022	279.12
Apr. 1, 2015	207.96	Oct. 1, 2018	241.36	Apr. 1, 2022	280.11
May 1, 2015	208.70	Nov. 1, 2018	242.21	May 1, 2022	281.10
Jun. 1, 2015	209.44	Dec. 1, 2018	243.07	Jun. 1, 2022	282.10
Jul. 1, 2015	210.19	Jan. 1, 2019	243.94	Jul. 1, 2022	283.10
Aug. 1, 2015	210.93	Feb. 1, 2019	244.80	Aug. 1, 2022	284.11
Sep. 1, 2015	211.68	Mar. 1, 2019	245.67	Sep. 1, 2022	285.12
Oct. 1, 2015	212.44	Apr. 1, 2019	246.54	Oct. 1, 2022	286.13
Nov. 1, 2015	213.19	May 1, 2019	247.42	Nov. 1, 2022	287.15
Dec. 1, 2015	213.95	Jun. 1, 2019	248.30	Dec. 1, 2022	288.17
Jan. 1, 2016	214.71	Jul. 1, 2019	249.18	Jan. 1, 2023	289.19
Feb. 1, 2016	215.47	Aug. 1, 2019	250.07	Feb. 1, 2023	290.22
Mar. 1, 2016	216.23	Sep. 1, 2019	250.95	Mar. 1, 2023	291.25
Apr. 1, 2016	217.00	Oct. 1, 2019	251.85	Apr. 1, 2023	292.28
May 1, 2016	217.77	Nov. 1, 2019	252.74	May 1, 2023	293.32
Jun. 1, 2016	218.55	Dec. 1, 2019	253.64	Jun. 1, 2023	294.36
Jul. 1, 2016	219.32	Jan. 1, 2020	254.54	Jul. 1, 2023	295.41
Aug. 1, 2016	220.10	Feb. 1, 2020	255.44	Aug. 1, 2023	296.46
Sep. 1, 2016	220.88	Mar. 1, 2020	256.35	Sep. 1, 2023	297.51
Oct. 1, 2016	221.67	Apr. 1, 2020	257.26	Oct. 1, 2023	298.57
Nov. 1, 2016	222.46	May 1, 2020	258.17	Nov. 1, 2023	299.63
Dec. 1, 2016	223.25	Jun. 1, 2020	259.09	Dec. 1, 2023	300.69
Jan. 1, 2017	224.04	Jul. 1, 2020	260.01	Jan. 1, 2024	301.76
Feb. 1, 2017	224.83	Aug. 1, 2020	260.93	Feb. 1, 2024	302.83
Mar. 1, 2017	225.63	Sep. 1, 2020	261.86	Mar. 1, 2024	303.91
Apr. 1, 2017	226.43	Oct. 1, 2020	262.79	Apr. 1, 2024	304.99
May 1, 2017	227.24	Nov. 1, 2020	263.72	May 1, 2024	306.07
Jun. 1, 2017	228.05	Dec. 1, 2020	264.66	Jun. 1, 2024	307.16
Jul. 1, 2017	228.86	Jan. 1, 2021	265.60	Jul. 1, 2024	308.25
Aug. 1, 2017	229.67	Feb. 1, 2021	266.54	Aug. 1, 2024	309.34
Sep. 1, 2017	230.48	Mar. 1, 2021	267.49	Sep. 1, 2024	310.44
Oct. 1, 2017	231.30	Apr. 1, 2021	268.44	Oct. 1, 2024	311.54
Nov. 1, 2017	232.12	May 1, 2021	269.39	Nov. 1, 2024	312.65
Dec. 1, 2017	232.95	Jun. 1, 2021	270.35	Dec. 1, 2024	313.76
Jan. 1, 2018	233.78	Jul. 1, 2021	271.31	Jan. 1, 2025	314.87
Feb. 1, 2018	234.61	Aug. 1, 2021	272.28	Feb. 1, 2025	315.99
Mar. 1, 2018	235.44	Sep. 1, 2021	273.24	Mar. 1, 2025	317.11
Apr. 1, 2018	236.28	Oct. 1, 2021	274.21	Apr. 1, 2025	318.24
May 1, 2018	237.11	Nov. 1, 2021	275.19	May 1, 2025	319.37
Jun. 1, 2018	237.96	Dec. 1, 2021	276.16	Jun. 1, 2025	320.51

Date	Accreted Value	Date	Accreted Value	Date	Accreted Value
Jul. 1, 2025	$321.64	Jun. 1, 2028	$364.14	May 1, 2031	$412.25
Aug. 1, 2025	322.79	Jul. 1, 2028	365.43	Jun. 1, 2031	413.71
Sep. 1, 2025	323.93	Aug. 1, 2028	366.73	Jul. 1, 2031	415.18
Oct. 1, 2025	325.08	Sep. 1, 2028	368.03	Aug. 1, 2031	416.65
Nov. 1, 2025	326.24	Oct. 1, 2028	369.34	Sep. 1, 2031	418.13
Dec. 1, 2025	327.40	Nov. 1, 2028	370.65	Oct. 1, 2031	419.62
Jan. 1, 2026	328.56	Dec. 1, 2028	371.97	Nov. 1, 2031	421.11
Feb. 1, 2026	329.73	Jan. 1, 2029	373.29	Dec. 1, 2031	422.60
Mar. 1, 2026	330.90	Feb. 1, 2029	374.61	Jan. 1, 2032	424.11
Apr. 1, 2026	332.07	Mar. 1, 2029	375.94	Feb. 1, 2032	425.61
May 1, 2026	333.25	Apr. 1, 2029	377.28	Mar. 1, 2032	427.12
Jun. 1, 2026	334.44	May 1, 2029	378.62	Apr. 1, 2032	428.64
Jul. 1, 2026	335.62	Jun. 1, 2029	379.96	May 1, 2032	430.16
Aug. 1, 2026	336.82	Jul. 1, 2029	381.31	Jun. 1, 2032	431.69
Sep. 1, 2026	338.01	Aug. 1, 2029	382.67	Jul. 1, 2032	433.22
Oct. 1, 2026	339.21	Sep. 1, 2029	384.03	Aug. 1, 2032	434.76
Nov. 1, 2026	340.42	Oct. 1, 2029	385.39	Sep. 1, 2032	436.31
Dec. 1, 2026	341.63	Nov. 1, 2029	386.76	Oct. 1, 2032	437.86
Jan. 1, 2027	342.84	Dec. 1, 2029	388.13	Nov. 1, 2032	439.41
Feb. 1, 2027	344.06	Jan. 1, 2030	389.51	Dec. 1, 2032	440.97
Mar. 1, 2027	345.28	Feb. 1, 2030	390.90	Jan. 1, 2033	442.54
Apr. 1, 2027	346.51	Mar. 1, 2030	392.28		
May 1, 2027	347.74	Apr. 1, 2030	393.68		
Jun. 1, 2027	348.97	May 1, 2030	395.08		
Jul. 1, 2027	350.21	Jun. 1, 2030	396.48		
Aug. 1, 2027	351.45	Jul. 1, 2030	397.89		
Sep. 1, 2027	352.70	Aug. 1, 2030	399.30		
Oct. 1, 2027	353.96	Sep. 1, 2030	400.72		
Nov. 1, 2027	355.21	Oct. 1, 2030	402.14		
Dec. 1, 2027	356.47	Nov. 1, 2030	403.57		
Jan. 1, 2028	357.74	Dec. 1, 2030	405.00		
Feb. 1, 2028	359.01	Jan. 1, 2031	406.44		
Mar. 1, 2028	360.29	Feb. 1, 2031	407.88		
Apr. 1, 2028	361.57	Mar. 1, 2031	409.33		
May 1, 2028	362.85	Apr. 1, 2031	410.79		

DESCRIPTION OF BOOK-ENTRY ONLY SYSTEM

Unless and until the book-entry only system is discontinued, the 2014M1 Bonds will be available only in book-entry form in authorized denominations. Owners of the 2014M1 Bonds will be listed in the books of record of the Registrar. Owners of the 2014M1 Bonds will not receive physical bond certificates representing their interests in the 2014M1 Bonds purchased.

Transfers of ownership interests in the 2014M1 Bonds are to be accomplished by entries made on the books of the Trustee acting on behalf of Owners. Owners will not receive certificates representing their ownership interests in the 2014M1 Bonds, unless the use of the book-entry system for the 2014M1 Bonds is discontinued.

LONG-TERM CAPITAL STRUCTURE PLAN

Traditionally, the Authority has amortized its debt taking into consideration the potential termination of the Central Agreement hereafter defined, and the expected lives of its capital assets. See “CUSTOMER BASE -- Wholesale - Central.” In light of the May 20, 2013 extension of the earliest possible termination date of the Central Agreement from 2030 to 2058, the Authority intends to extend the average life of its debt in order to better align its debt amortization to the expected lives of its capital assets. The Authority will achieve this alignment by a combination of selling longer dated debt for the Authority’s current and future capital projects, combined with a multi-year refinancing program that will extend the maturity of a portion of the Authority’s debt. The ultimate amount of debt extension will be impacted by a number of factors, including the Authority’s ownership percentage of the new nuclear units described below. While the size and scope of this restructuring program will evolve over time, the Authority currently projects that up to $900 million of bonds maturing through 2031 could be refunded and extended over the term of this program. As an alternative to a portion of these potential refundings, the Authority may obtain a portion of its desired debt alignment by deferring the principal amortization of future capital project issues.

FINANCING PLAN FOR SUMMER NUCLEAR UNITS 2 AND 3

The Authority currently estimates the total construction cost associated with a 45% ownership interest in the Virgil C. Summer Nuclear Generating Station Units 2 and 3 (“Summer Nuclear Unit 2" and “Summer Nuclear Unit 3” and together “Summer Nuclear Units 2 and 3") to be approximately $5.1 billion including approximately $159 million for transmission and approximately $138 million for the initial fuel core. Except for a small portion of the transmission cost associated with Summer Nuclear Units 2 and 3, the Authority expects to fund the construction with debt and with the proceeds of a sale of a portion of its ownership interest in Summer Nuclear Units 2 and 3 to South Carolina Electric & Gas (“SCE&G”). To date, the Authority has financed approximately $2.5 billion for construction from proceeds of issues sold beginning in 2008. The remaining requirements for construction are approximately $2.6 billion. The Authority intends to fund the remaining construction with the proceeds of additional bond sales projected in calendar years 2014 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 parity indebtedness, 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. See “CAPITAL IMPROVEMENT PROGRAM -- Summer Nuclear Units 2 and 3.”

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DEBT SERVICE SCHEDULE(1)
(Thousands of Dollars)

The following table sets forth on an accrual basis the debt service due on outstanding Revenue Obligations, the 2014M1 Bonds, and the total debt service in each calendar year indicated.

	Outstanding Revenue Obligations(2)	2014M1 Bonds	Total Debt Service
2014	$ 497,447	$ 807	$ 498,255
2015	842,187(3)	1,211	843,398
2016	609,399(3)	1,211	610,610
2017	452,391	1,211	453,602
2018	468,813	5,474	474,287
2019	435,682	1,136	436,819
2020	426,936	1,136	428,073
2021	441,087	1,136	442,224
2022	368,615	4,463	373,078
2023	334,020	5,171	339,191
2024	336,882	1,015	337,897
2025	314,380	1,015	315,396
2026	314,930	1,015	315,945
2027	316,571	4,500	321,072
2028	326,138	7,897	334,035
2029	331,640	740	332,381
2030	304,945	740	305,685
2031	283,205	740	283,945
2032	256,843	6,480	263,322
2033	284,973	17,954	302,927
2034	286,911		286,911
2035	304,831		304,831
2036	305,682		305,682
2037	264,646		264,646
2038	222,839		222,839
2039	203,921		203,921
2040	225,606		225,606
2041	225,615		225,615
2042	222,359		222,359
2043	226,166		226,166
2044	147,426		147,426
2045	144,231		144,231
2046	141,714		141,714
2047	139,201		139,201
2048	135,607		135,607
2049	121,363		121,363
2050	59,519		59,519
2051	59,516		59,516
2052	59,515		59,515
2053	54,563		54,563

(1) Does not include payments into the Lease Fund or debt service on Commercial Paper Notes, both of which are junior to debt service on Revenue Obligations. Does not reflect puts subsequent to December 15, 2013 of Revenue Obligations subject to tender for elective purchase.
(2) Net of Subsidy Payment (hereinafter defined). Subject to the Authority's compliance with certain requirements under the American Recovery and Reinvestment Act of 2009 and the Internal Revenue Code of 1986, as amended (the "Code"), the Authority expects to receive cash subsidy payments from the United States Treasury equal to 35% of the interest payable on the Revenue Obligations, 2010 Series C Bonds (the "2010C Bonds") (any such payment, a "Subsidy Payment"). Pursuant to the requirements of the Balanced Budget and Emergency Deficit Control Act of 1985, as amended, certain automatic reductions took place March 1, 2013. These required reductions includes a reduction to refundable credits under section 6431 of the Internal Revenue Code applicable to certain qualified bonds. The sequestration reduction rate of 7.2% has been applied to the July 1, 2014 and January 1, 2015 Subsidy Payments respectively, and the debt service on Revenue Obligations in calendar years 2014 and 2015 has been adjusted accordingly.
(3) Includes actual interest on the $450,000,000 2013 Taxable Series D (LIBOR Index Bonds) through June 2, 2014, and thereafter based on a projected 1 Month LIBOR rate of 1.00%. Principal on the LIBOR Index Bonds is shown in the year due rather than on an accrual basis.

SECURITY FOR THE 2014M1 BONDS

General

The 2014M1 Bonds are payable solely from, and secured by a lien upon and pledge of, the Revenues on a parity with the lien and pledge securing Revenue Obligations heretofore and hereafter issued pursuant to the Revenue Obligation Resolution, senior to (i) payments required to be made from or retained in the Revenue Fund to pay expenses of operating and maintaining the System, and (ii) the payments into the Lease Fund and the Capital Improvement Fund heretofore established and continued under the Revenue Obligation Resolution. See "FINANCIAL INFORMATION." In the Revenue Obligation Resolution the Authority has covenanted not to incur any indebtedness senior to the lien of the Revenue Obligations.

The Revenue Obligations, including the 2014M1 Bonds, are not obligations of the State, nor of any political subdivision thereof, and neither the State nor any of its political subdivisions shall be liable thereon, nor shall they be payable from any funds other than the Revenues of the Authority pledged to the payment thereof.

Additional series of Revenue Obligations may be issued without limitation and without compliance with any additional bonds test, provided there is no default under the Revenue Obligation Resolution. In addition, no debt service reserve fund is established under the Revenue Obligation Resolution. See Appendix II -- "SUMMARY OF CERTAIN PROVISIONS OF THE REVENUE OBLIGATION RESOLUTION."

Rate Covenant

The Revenue Obligation Resolution provides that the Authority shall establish, maintain and collect rents, tolls, rates and other charges for power and energy and all other services, facilities and commodities sold, furnished or supplied through the facilities of the System which shall be adequate to provide the Authority with Revenues sufficient: (a) to pay the principal of, premium, if any, and interest on the Revenue Obligations as and when the same shall become due and payable; (b) to make when due all payments which the Authority is obligated to make (i) into the Revenue Obligation Fund created under the Revenue Obligation Resolution, (ii) into the Lease Fund, and (iii) into the Capital Improvement Fund pursuant to the Revenue Obligation Resolution; (c) to make all other payments which the Authority is obligated to make pursuant to the Revenue Obligation Resolution; (d) to pay all proper operation and maintenance expenses and all necessary repairs, replacements and renewals thereof; (e) to pay all taxes, assessments or other governmental charges lawfully imposed on the Authority or the Revenues thereof or payments in lieu thereof; and (f) to pay any and all amounts which the Authority may become obligated to pay from the Revenues of the System by law or by contract.

As required by the Act, the Authority makes distributions to the State and payments in lieu of taxes to local governments. Nothing in the Act prohibits the Authority from paying to the State each year up to 1% of its projected operating revenues, as such revenues would be determined on an accrual basis, from the combined electric and water systems. In 2013, distributions to the State and payments to local governments amounted to approximately $30,525,000.

There is no governmental or regulatory entity, other than the Authority's Board of Directors, having jurisdiction over the rates of the Authority.

Additional Indebtedness

The Revenue Obligation Resolution does not prohibit the issuance of obligations secured by a pledge of the Revenues junior and subordinate to the pledge securing the Revenue Obligations. In addition, the Authority may issue obligations secured by a pledge of revenues derived from separate utility systems not included in the System. See Appendix II -- "SUMMARY OF CERTAIN PROVISIONS OF THE REVENUE OBLIGATION RESOLUTION -- Separate Systems."

Capital Improvement Fund Requirement

The Revenue Obligation Resolution requires, so long as any Revenue Obligations are outstanding, that the Authority deposit annually into the Capital Improvement Fund an amount which, together with the amounts deposited therein in the two immediately preceding Fiscal Years, will be at least equal to 8% of the Revenues required by the Revenue Obligation Resolution to be paid into the Revenue Fund in the three immediately preceding Fiscal Years. Permitted use of moneys in the Capital Improvement Fund includes but is not limited to payment of Capital Costs, as defined in the Revenue Obligation Resolution. See Appendix II --"SUMMARY OF CERTAIN PROVISIONS OF THE REVENUE OBLIGATION RESOLUTION."

ORGANIZATION AND MANAGEMENT OF THE AUTHORITY

The Act contains provisions governing the composition, qualifications, appointment and duties of the Authority's Board of Directors. The Governor appoints members, and the State Regulation of Public Utilities Review Committee ("PURC") screens appointees to determine whether they have the qualifications required by the Act. After successful screening, appointees must be confirmed by the State Senate. The Act describes the duties of directors and sets forth conditions by which a director may be held accountable for his actions or inactions as a director.

The Board consists of twelve members who reside in South Carolina as follows: one from each congressional district of the State; one from each of the counties of Berkeley, Horry and Georgetown who reside in the territory of the Authority and are customers of the Authority, and two from the State at large, one of whom shall be chairman. Two of the directors must have substantial work experience within the operations of electric cooperatives or substantial experience on an electric cooperative board, but must not serve as an employee or board member of an electric cooperative during their term as director of the Authority. One of the two must have substantial experience within the operations or board of a transmission or generation cooperative.

Directors serve for a term of seven years and until a successor has been appointed and found qualified. Directors appointed to fill a vacancy on the Board serve for the unexpired portion of the term and until a successor is appointed and found qualified. An individual appointed and found qualified by the PURC while the State Senate is not in session may serve as director in an interim capacity. Directors may be removed from office only for cause.

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Present directors are listed below. The board terms for Directors Barry D. Wynn and Peggy H. Pinnell have expired, but Board Members may continue to serve until successors have been appointed and qualified.

On February 20, 2014, the Governor re-appointed Director Kristofer Clark as Director for the Third Congressional District, re-appointed Director J. Calhoun Land, IV as Director for the Sixth Congressional District, appointed Jack Wolfe as Director for the Second Congressional District, appointed Merrill Floyd as Director for the previously vacant Seventh Congressional District, appointed Dan Ray as Director for Georgetown County and appointed Catherine Heigel to the at-large position previously held by Director Cecil Viverette. The appointments were confirmed by the Senate on May 1, 2014 and the Directors took office.

Name	Business	Residence	Term Expires May
W. Leighton Lord, III, Chairman	Attorney	Columbia	2018
William A. Finn, First Vice Chairman	Business Executive	Charleston	2020
Barry D. Wynn, Second Vice Chairman	Business Executive	Spartanburg	2014(1)
Peggy H. Pinnell	Business Executive	Moncks Corner	2014(1)
Danny J. Ray	Business Executive	Pawleys Island	2015
Jack F. Wolfe, Jr.	Retired Business Executive	Chapin	2015
David F. Singleton	Business Executive	Myrtle Beach	2016
Kristofer D. Clark	Business Executive	Easley	2019
Merrell W. Floyd	Retired Business Executive	Conway	2019
Catherine E. Heigel	Business Executive	Greenville	2019
J. Calhoun Land, IV	Attorney	Manning	2020

(1) Although their terms expired as indicated, they may continue to serve until successors have been appointed and qualified.

The President and Chief Executive Officer of the Authority is appointed by the Authority's Board of Directors. The Authority's executive management is appointed by the President and Chief Executive Officer with the approval of the Authority's Board of Directors.

Authority executive management is:

Name	Position	Utility Experience
Lonnie N. Carter	President and Chief Executive Officer	31 years
James E. Brogdon, Jr.	Executive Vice President and General Counsel	9 years
Jeffrey D. Armfield	Senior Vice President and Chief Financial Officer	30 years
Michael R. Crosby	Senior Vice President, Nuclear Energy	29 years
Robert B. Fleming, Jr.	Senior Vice President, Power Delivery	21 years
L. Phil Pierce	Senior Vice President, Generation	35 years
Marc R. Tye	Senior Vice President, Customer Service	31 years
Pamela J. Williams	Senior Vice President, Corporate Services	12 years

Lonnie N. Carter joined the Authority in 1982 as an employee in the Controller's Office. Since that time he has held various positions, including Manager of Corporate Forecasting, Vice President of Corporate Forecasting, Senior Vice President of Customer Service and Senior Vice President of Corporate Planning & Bulk Power. In 1997, he served as the first President and Chief Executive Officer of The Energy Authority, Inc. ("TEA"), a joint power marketing alliance through a non-profit corporation, whereby the Authority can purchase or sell energy and/or capacity when available. In 2004, he became President and Chief Executive Officer. He received a Bachelor of Science degree in Business Administration and a Masters in Business Administration from The Citadel.

James E. Brogdon, Jr. joined the Authority in 2005 as Senior Vice President and General Counsel and a member of the executive management team. He practiced law in private practice and served as a judge of the South Carolina Circuit Court from 1996 to February 2005. He received a Bachelor of Arts degree in Economics from Wofford College and a Juris Doctor degree from the University of South Carolina School of Law. James E. Brogdon, Jr. will retire on June 30, 2014. Effective July 1, 2014, J. Michael Baxley will become Senior Vice President and General Counsel.

Jeffrey D. Armfield joined the Authority in 1983 as a Senior Auditor. Since that time he has held various positions, including Vice President, Fuels Strategy and Supply, Treasurer and Director of Financial Planning. He received a Bachelor of Science degree in Business and a Masters in Business Administration from The Citadel and is a Certified Public Accountant.

Michael R. Crosby became Senior Vice President, Nuclear Energy, on May 1, 2014. He joined the Authority in 1985 as an engineer. Since that time, he has held various positions, including Manager of Station Construction and Vice President, Nuclear Operations and Construction. He received a Bachelor of Science degree in electrical engineering from the University of South Carolina and a Masters in Business Administration from The Citadel.

Robert B. Fleming, Jr. joined the Authority in 1992 as an engineer. Since that time he has held various positions including Manager of Transmission Operations, Superintendent of System Substation Maintenance and Supervisor of Mechanical Maintenance at Cross Generating Station. He received a Bachelor of Science degree in Electrical Engineering from the University of South Carolina and a Masters in Business Administration from The Citadel.

L. Phil Pierce joined the Authority in 1979 as an engineer. Since that time he has held various positions, including Manager of Performance & Environmental Services and Manager of Cross Station Construction. He received a Bachelor of Science degree in Mechanical Engineering from Clemson University.

Marc R. Tye joined the Authority in 1984 as an engineer. Since that time he has held various positions, including Manager of Corporate Analysis & Pricing and Manager of Wholesale Markets. He received a Bachelor of Science degree in Electrical Engineering and a Masters in Business Administration from The Citadel.

Pamela J. Williams became Senior Vice President, Corporate Services on May 1, 2014. She joined the Authority in 2001 as Associate General Counsel for Corporate Affairs. In 2006, she took on the additonal duties of corporate secretary. She moved to Vice President, Administration in 2011. Prior to joining the Authority she served as corporate counsel for The Clorox Company. She received a Bachelor of Science degree in Economics from the College of Charleston and a Juris Doctor degree from the University of Virginia School of Law.

The Authority had 1,722 employees as of March 31, 2014. Authority employees are members of a contributory state pension plan administered by the South Carolina State Retirement System.

The Act establishes an Advisory Board composed of the following officials of the State: the Governor, the Attorney General, the State Treasurer, the Comptroller General and the Secretary of State. The Advisory Board approves the hiring of the external auditors and sets the salary of the Authority's Board of Directors.

CUSTOMER BASE

Service Area

The Authority's primary business operation is the production, transmission and distribution of electrical energy, both at wholesale and retail, to citizens of South Carolina. In 2013, the Authority's kilowatt-hour ("kWh") energy sales were comprised of 57.8% to wholesale customers, 28.1% to large industrial customers and 14.1% to residential, commercial and other customers. The Authority is one of the nation's largest municipal wholesale utilities, whose System serves directly or indirectly approximately 2 million South Carolinians in all 46 counties of South Carolina. The Authority serves directly and indirectly suburban areas outside Charleston, Columbia, Greenville and Spartanburg as well as the coastal areas of Myrtle Beach and the Grand Strand, Hilton Head Island, Kiawah Island and Seabrook Island. See "HISTORICAL SALES – Historical Demand, Sales and Revenues."

The Authority's direct customers currently include 27 large industrial customers, Central Electric Power Cooperative Inc. (“Central”), and two municipal electric systems, the City of Georgetown and the City of Bamberg. Central is an association of 20 electric distribution cooperatives, including the five electric distribution cooperatives that were formerly members of Saluda River Electric Cooperative, Inc. (“Saluda”). Central serves primarily residential, commercial and small industrial customers in all 46 counties of the State. Through Central and the two municipal electric systems, the Authority indirectly serves approximately 747,000 customers. See “CUSTOMER BASE - Wholesale - Central” and “CUSTOMER BASE - Wholesale - Other.”

The Authority also serves directly approximately 169,000 residential, commercial and small industrial retail customers in its assigned retail service territory, which includes parts of Berkeley, Georgetown and Horry counties. See “CUSTOMER BASE - Direct Retail Service Area.”

Under State law, the Authority has an exclusive right to serve within its assigned retail service territory, and it has the exclusive right to continue to serve the large industrial premises outside its assigned service territory that it is currently serving. If after July 9, 1973, any customers, premises, or electric cooperatives located outside the present service area of the Authority and being served by the Authority, included any subsequent expansions or additions by such customers, premises, or cooperatives, ceases or discontinues accepting electrical service from the Authority, the Authority may subsequently sell and furnish electrical service to new customers, premises, or electrical cooperatives from its major transmission lines in an amount not exceeding the amount of power the sale of which was lost by reason of such discontinuation of service.

Wholesale - Central

Central is a generation and transmission cooperative that provides wholesale electric service to each of the 20 distribution cooperatives (the “Central Cooperatives”) which are members of Central pursuant to long-term all requirements power supply agreements. The Central Cooperatives serve areas ranging from sparsely populated rural areas to heavily populated suburban areas. The table below lists each of the Central Cooperatives, the location of their headquarters, and the number of customers of each as of December 31, 2013.

Central Cooperatives	Headquarters	Customers
Aiken Electric Cooperative, Inc.	Aiken	45,802
Berkeley Electric Cooperative, Inc.	Moncks Corner	86,126
Black River Electric Cooperative, Inc.	Sumter	31,632
Blue Ridge Electric Cooperative, Inc.(1)	Pickens	63,687
Broad River Electric Cooperative, Inc.(1)	Gaffney	20,494
Coastal Electric Cooperative, Inc.	Walterboro	11,530
Edisto Electric Cooperative, Inc.	Bamberg	19,918
Fairfield Electric Cooperative, Inc.	Winnsboro	26,590
Horry Electric Cooperative, Inc.	Conway	70,321
Laurens Electric Cooperative, Inc.(1)	Laurens	54,132
Little River Electric Cooperative, Inc.(1)	Abbeville	14,014
Lynches River Electric Cooperative, Inc.	Pageland	20,608
Marlboro Electric Cooperative, Inc.	Bennettsville	6,489
Mid-Carolina Electric Cooperative, Inc.	Lexington	53,224
Newberry Electric Cooperative, Inc.	Newberry	12,025
Palmetto Electric Cooperative, Inc.	Ridgeland	67,940
Pee Dee Electric Cooperative, Inc.	Darlington	30,245
Santee Electric Cooperative, Inc.	Kingstree	43,977
Tri-County Electric Cooperative, Inc.	St. Matthews	17,851
York Electric Cooperative, Inc.(1)	York	46,521

(1) Former members of Saluda (“Former Saluda Members”).

The Authority serves Central under the terms of an agreement between the Authority and Central which became effective in January 1981 (as subsequently amended or revised, the “Central Agreement”). In 2013, revenues pursuant to the Central Agreement amounted to approximately 57.8% of revenues from sales. The Authority and Central adopted an amendment to the Central Agreement in January 1988 which included a number of revisions to the cost of service methodology, established that the Authority would supply the total power and energy requirements of the Central Cooperatives (with some limited exceptions) and provided that the Central Agreement would have a perpetual duration with a 35 year initial term ending March 31, 2023 and an automatic renewal for successive 35 year periods, subject to the right of either party to terminate the Central Agreement on any date on or after the end of such initial 35 year term, upon giving at least 10 years' notice.

September 2009 Agreement. In September 2009 Central and the Authority entered into an agreement (the "September 2009 Agreement") that, among other things, provided that neither party would exercise its right to terminate the Central Agreement effective on or before December 31, 2030. The Authority agreed in the September 2009 Agreement to allow Central to transition the purchase of the portion of the power and energy requirements of the five Former Saluda Members directly connected to the transmission system of Duke Energy Carolinas, LLC ("Duke Energy Carolinas") (the "Upstate Load") to another supplier and in January 2013, Central began transitioning the Upstate Load to Duke Energy Carolinas, a subsidiary of Duke Energy Corporation ("Duke"). The Upstate Load, which is approximately 22% of Central's current energy requirements, will transition to Duke Energy Carolinas over a six-year period beginning in 2013, and by the end of the transition in 2019, will amount to approximately 1,000 Megawatts ("MW").

May 2013 Revision to the Central Agreement. The Authority and Central adopted an amendment to the Central Agreement on May 20, 2013 (the "May 2013 Revision") that better aligns their future interests, formalizes how they will jointly plan for new resources, and defers their rights to terminate the agreement until December 31, 2058. Under the Central Agreement's 10 year rolling notice provisions, 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 requirements 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.

Rates under the Central Agreement continue to be developed under a cost of service methodology and to be adjusted automatically on a monthly basis to reflect actual fuel cost and to be adjusted on an annual basis to reflect actual non-fuel cost, including O&M, debt service and a Capital Improvement Fund charge. Modifications to the cost of service methodology include allocating debt service and Capital Improvement Fund charges to the cost categories based on plant balances and allocating production related cost in a manner that reflects the nature of the generating resources.

Under the May 2013 Revision the requirements provisions of the Central Agreement are retained. Central will continue to pay for its pro-rata share of the existing system resources, including Summer Nuclear Units 2 and 3. The May 2013 Revision formalizes the resource planning process and outlines how the parties will jointly plan and determine the need for new resources. The May 2013 Revision also contains provisions that allow Central to decide to participate or not participate in major new resources which were not completed or under construction as of January 1, 2013. If Central decides to participate in a resource, the costs for the new resource are included and shared under the Central Agreement. If Central decides not to participate in a proposed resource, the parties will obtain their own resources based on their pro-rata share of the proposed resource and each party will be responsible for the cost of its own non-shared resources.

The May 2013 Revision provides certainty to the planning process and, with the earliest termination date deferred to December 2058, will allow the Authority to align its existing and future debt service with the useful lives of its assets and its future revenue stream.

The Authority supplies the total power and energy requirements of the Central Cooperatives less amounts which Central purchases directly from Southeastern Power Administration (the "SEPA"), amounts provided by Broad River Electric Cooperative's ownership interest in a small run of the river hydroelectric plant, amounts provided by Duke Energy Carolinas under the September 2009 Agreement referenced above, and small amounts purchased from others.

Palmetto Economic Development Corporation. Central and the Authority have joined together to form a joint economic development effort, known as the Palmetto Economic Development Corporation, to benefit the State, the Authority and Central. Formed in September 1988, it works to more effectively recruit new industries and to increase job opportunities throughout the State. The joint operation is governed by an eight-member board of directors, four named by Central and four named by the Authority. In February 2012, the Authority and Central announced economic development rates for new and expanded large industrial loads to further enhance their economic development efforts.

Wholesale - Other

In addition to Central, the Authority provides wholesale electric service to the City of Georgetown, the City of Bamberg, and SCE&G pursuant to long-term contracts. New service agreements were executed in 2013 with the City of Georgetown and the City of Bamberg for 10 years and 20 years, respectively. Sales to these customers and off-system sales to other utilities and power marketers during 2013 represented approximately 1.2% of revenues from sales.

The Authority has a long-term power agreement with Piedmont Municipal Power Agency ("PMPA") pursuant to which the Authority provides PMPA its supplemental electric power and energy requirements (ranging from approximately 200 MW to 300 MW) above its current resources. This agreement commenced on January 1, 2014, for a term of no less than 12 years.

The Authority also has an agreement pursuant to which it provides Alabama Municipal Electric Authority 50 MW unit-contingent capacity and associated energy (25 MW-50 MW). This agreement commenced on January 1, 2014, for a term of 10 years.

Direct Retail Service Area

The Authority owns distribution facilities and serves in two non-contiguous areas covering portions of Berkeley, Georgetown and Horry Counties. These service areas include 2,787 miles of distribution lines. The following table presents retail customer growth from 2009 through 2013 in these areas.

Retail Customers

Year	Residential	Commercial and Small Industrial	Total	Annual Increase %
2009	133,229	29,752	162,981	0.2
2010	134,704	28,897	163,601	0.4
2011	136,047	28,600	164,647	0.6
2012	138,353	28,456	166,809	1.3
2013	140,126	28,687	168,813	1.2

Sales to residential, commercial, small industrial customers and certain other customers are made pursuant to rate schedules established from time to time by the Authority. The vast majority of such rate schedules include monthly automatic fuel adjustment and demand sales adjustment clauses. Sales to this customer group represented approximately 19.8% of revenues from sales in 2013.

Large Industrial Contracts

Sales to large industrial customers are made pursuant to long-term contracts. The Authority offers a large power rate schedule prepared on a cost of service basis for large industrial customers which contract for a minimum of 1,000 kilowatts ("kW"). The Authority requires that such customers enter into contracts for initial periods of not less than five years. All contracts contain rate provisions of the demand and energy type, and include monthly automatic fuel adjustment and demand sales adjustment clauses, minimum demand charges and other provisions generally used in large industrial power rate schedules. The average cost per kWh varies depending upon the customer's usage and load factor.

Sales to large industrial customers during 2013 represented approximately 21.2% of revenues from sales, which includes 8.9% for Alumax of South Carolina, Inc. ("Alumax"), 5.0% for Nucor Corporation ("Nucor"), and 5.2% for the next eight largest industrial customers, of which no one customer represents more than 1.5% of sales. Of the 21.2% of revenues from sales, approximately 66.8% represents fuel cost recovery.

Long-Term Power Contract with Alumax. The Authority has a long-term power contract with Alumax which extends through December 31, 2015. The contract provides for the delivery of approximately 400 MW of power under three different rate schedules or riders. Approximately 25% of the load is currently served under the Authority's firm industrial rate schedule, with the majority of the remainder served under the supplemental curtailable schedule. A small portion of the load is served under the interruptible rate schedule. Alumax's obligations under the contract are guaranteed by its parent company, Alcoa, Inc. The contract contains a provision that Alumax must notify the Authority by June 30, 2014 if it intends to cease operations after December 31, 2015.

In addition to its standard termination provisions, the contract contains a provision that allows for early termination if certain conditions based on the price of aluminum are met. At this time, conditions have been met that would allow Alumax to terminate the contract with six months prior notice, but Alumax has not given the Authority notice it intends to exercise its right to terminate.

Long-Term Power Contract with Nucor. The Authority has a long-term power contract with Nucor which extends through April 30, 2015 and provides for two year rollover terms thereafter. Under the notice provisions of the Authority's large light and power service, Nucor would have to provide four years notice to bring their load to zero. Such notice has not been given. The contract currently provides for delivery of approximately 300 MW of power, the majority of which is provided under the interruptible rate schedule.

RATES AND RATE COMPARISON

Rates

The Authority's Board of Directors is empowered and required to set rates as necessary to provide for expenses, including debt service, of the Authority. The Authority monitors rates and management recommends adjustments as necessary. On September 11, 2012, the Authority's Board of Directors approved a series of two base rate adjustments for its retail, industrial and municipal customers. The adjustments increased total charges for customers an average 3.5 percent each year for a total increase of 7 percent to ensure rates are at least adequate to provide revenues sufficient to pay debt service, the cost of operation and maintenance of the Authority's System, and meet the Revenue Obligation requirements for transfers to the Capital Improvement Fund, and all other such costs as necessary. The first adjustment took effect December 1, 2012 and the second took effect on December 1, 2013.

The Authority has developed and offers time-of-use, non-firm and off-peak rates to its direct-served commercial and industrial customers to encourage them to reduce their peak demand. As of December 31, 2013, the Authority had 834 MW of non-firm power under contract. The Authority also has seasonal energy charges for most rates affecting residential, commercial, and industrial customers. Seasonal energy charges reflect higher charges during the summer months when higher energy costs are incurred. The Authority's rate schedules include monthly automatic fuel adjustment clauses which provide for increases or decreases to the basic rate schedules to cover increases or decreases in the cost of fuel to the extent such costs vary from a predetermined base cost. The Authority's rate schedules also include a demand sales adjustment clause which provides for increases or decreases to the basic rate schedules to reflect increases or decreases in demand revenues from non-firm sales (such as supplemental curtailable, interruptible and economy power rate schedules and riders) and off-system sales to the extent such revenues vary from predetermined amounts included as credits to firm base rates.

Rates under the Central Agreement, as amended, are determined in accordance with the cost of service methodology contained in the Central Agreement. Under the Central Agreement, Central initially pays for its power supply based on the Authority's projected costs and loads. The charges are then adjusted, on an annual basis, to reflect actual costs and load and Central is charged or credited the difference between the amounts paid based on projected rates and the amounts due based on actual rates. For a more detailed discussion of the Central Agreement see "CUSTOMER BASE - Wholesale - Central."

During 2013 revenues from sales to wholesale requirements customers averaged 6.95 cents per kWh, revenues from sales to large industrial customers averaged 5.14 cents per kWh, and revenues from sales to residential, commercial, small industrial and other customers averaged 9.63 cents per kWh based on the then current rates which included fuel adjustments and credits for demand sales adjustments.

Rate Comparison

The Authority has seasonal rates for the majority of its residential, commercial, and industrial customers. Comparisons of the Authority's average monthly bills for firm service at selected usage levels with the average monthly bills of the three investor-owned utilities that serve the State based on rates on file with the South Carolina Public Service Commission (the "PSC") as of July 31, 2013 and January 31, 2014 are set forth on the following page.

As of July 31, 2013 (Summer)

	Residential Electric Service			
	500 kWh	**1,000 kWh**	**2,000 kWh**	**3,000 kWh**
Authority	$62.14	$112.27	$212.54	$312.81
Duke Energy Carolinas	51.12	94.96	190.86	286.76
Duke Energy Progress	56.36	106.21	205.92	305.63
SCE&G	73.72	140.53	281.90	423.27

	Commercial Electric Service		
	3,000 kWh	**5,000 kWh**	**7,500 kWh**
Authority	$288.81	$471.35	$699.53
Duke Energy Carolinas	256.32	423.58	610.34
Duke Energy Progress	307.28	463.84	659.54
SCE&G	391.05	655.55	986.18

	Industrial Electric Service (¢/kWh)			
	1,000 kW 500,000 kWh	**2,000 kW 1,000,000 kWh**	**9,000 kW 5,000,000 kWh**	**40,000 kW 25,000,000 kWh**
Authority	7.48¢	7.20¢	6.70¢	6.37¢
Duke Energy Carolinas	5.65	5.36	5.07	4.98
Duke Energy Progress	7.41	7.36	7.03	6.63
SCE&G	8.37	8.18	7.73	7.41

As of January 31, 2014 (Non-Summer)

	Residential Electric Service			
	500 kWh	**1,000 kWh**	**2,000 kWh**	**3,000 kWh**
Authority	$60.55	$107.10	$200.20	$293.30
Duke Energy Carolinas	57.28	106.26	210.43	314.60
Duke Energy Progress	56.36	104.21	193.92	283.63
SCE&G	76.06	141.05	267.88	394.71

	Commercial Electric Service		
	3,000 kWh	**5,000 kWh**	**7,500 kWh**
Authority	$269.70	$437.50	$647.25
Duke Energy Carolinas	274.74	453.65	654.61
Duke Energy Progress	307.28	463.84	659.54
SCE&G	404.20	641.62	938.40

	Industrial Electric Service (¢/kWh)			
	1,000 kW 500,000 kWh	**2,000 kW 1,000,000 kWh**	**9,000 kW 5,000,000 kWh**	**40,000 kW 25,000,000 kWh**
Authority	7.17¢	6.87¢	6.31¢	5.95¢
Duke Energy Carolinas	6.46	6.16	5.82	5.67
Duke Energy Progress	7.41	7.36	7.03	6.63
SCE&G	8.61	8.41	7.95	7.62

POWER SUPPLY AND POWER MARKETING

Existing Generating Facilities

The Authority's generating facilities consist of the following facilities:

Generating Facilities(1)	Location	Initial Date in Service	Winter MCR(2) (MW)	Summer MCR(2) (MW)	Energy Source
Jefferies Hydroelectric Generating Station	Moncks Corner	1942	127	127	Hydro
Wilson Dam Generating Station	Lake Marion	1950	2	2	Hydro
Jefferies Generating Station	Moncks Corner				
Nos. 1 and 2(3)		1954	88	84	Oil
Combustion Turbines Nos. 1 and 2	Myrtle Beach	1962	20	16	Oil/Gas
Combustion Turbines Nos. 3 and 4	Myrtle Beach	1972	40	38	Oil
Combustion Turbine No. 5	Myrtle Beach	1976	25	21	Oil
Combustion Turbine No. 1	Hilton Head Island	1973	20	19	Oil
Combustion Turbine No. 2	Hilton Head Island	1974	20	19	Oil
Combustion Turbine No. 3	Hilton Head Island	1979	60	52	Oil
Winyah Generating Station	Georgetown				
No. 1		1975	280	275	Coal
No. 2		1977	290	285	Coal
No. 3		1980	290	285	Coal
No. 4		1981	290	285	Coal
Summer Nuclear Unit 1(4)	Jenkinsville	1983	318(5)	318(5)	Nuclear
Cross Generating Station	Cross				
Unit 1		1995	590	580	Coal
Unit 2		1983	585	570	Coal
Unit 3		2007	600	600	Coal
Unit 4		2008	600	600	Coal
Horry Landfill Gas Station	Conway	2001	3	3	LMG(6)
Lee County Landfill Gas Station	Bishopville	2005	11	11	LMG
Richland County Landfill Gas Station	Elgin	2006	8	8	LMG
Anderson County Landfill Gas Station.	Belton	2008	3	3	LMG
Georgetown County Landfill Gas Station	Georgetown	2010	1	1	LMG
Berkeley County Landfill Gas Station	Moncks Corner	2011	3	3	LMG
Rainey Generating Station	Starr				
Unit 1		2002	520	460	Gas
Unit 2A		2002	180	146	Gas
Unit 2B		2002	180	146	Gas
Unit 3		2004	90	75	Gas
Unit 4		2004	90	75	Gas
Unit 5		2004	90	75	Gas
Total Capability			5,424	5,182	

(1) Grainger Generating Station Nos. 1 and 2 and Jefferies Generating Station Nos. 3 and 4 were retired on December 31, 2012.
(2) Maximum Continuous Ratings ("MCR").
(3) These units will be retired within a timeline to be determined by the Authority's management and in compliance with applicable regulatory deadlines.
(4) Virgil C. Summer Nuclear Generating Station Unit 1 ("Summer Nuclear Unit 1").
(5) Represents the Authority's one-third ownership interest.
(6) Landfill Methane Gas ("LMG").

Existing Power Resources

The Authority plans for firm power supply from its own generating capacity and firm power contracts to equal its firm load, including a 15% summer reserve margin. The Authority's current total summer MCR of its owned generating capacity is set forth in the table below. The Authority presently receives 84 MW of firm supply from the U.S. Army Corps of Engineers (the "Corps") and 319 MW of firm hydroelectric power from SEPA. The SEPA allocation consists of 184 MW for wheeling to the SEPA preference customers served by the Authority and 135 MW purchased by the Authority for its customers. The Authority also receives 8 MW of dependable capability from the Buzzards Roost hydro electric generating facility which it leases from Greenwood County, South Carolina and 75 MW of biomass capacity and associated energy under four power purchase agreements (the first commenced in September 2010 and the most recent in November 2013, with varying terms from 15 to 30 years). There is also an agreement to purchase the output from a 2.5 MW solar photovoltaic facility that started producing power in December of 2013 and has a 20 year term. In addition, for the time period January 2011 through December 2014, the Authority has entered into an agreement with TEA for the purchase of unit-contingent power from a Southern Power Company simple cycle combustion turbine resource. This purchase is anticipated to provide a summer capability amount of 155 MW. The Authority has also entered into a purchase agreement with JP Morgan Ventures Energy Corporation for 300 MW of capacity and associated energy beginning June 1, 2012 and continuing through December 31, 2015. The electric generation, transmission and distribution facilities owned by the Authority as well as certain transmission facilities leased from Central, are operated by the Authority as a fully integrated electric system. The Authority has direct interconnections with five entities, including all those with which the Authority has long-term power contracts for energy interchange. See "POWER SUPPLY AND POWER MARKETING -- Interconnections and Interchanges."

The table below details the Authority's resources classified by energy source for the summer power supply peak capability.

Source of Power Supply	(MW)	% of Total
Coal	3,480	57.2
Natural Gas and Oil	1,226	20.1
Nuclear	318	5.2
Owned Hydro Generation	129	2.1
Landfill Methane Gas	29	0.5
Total MCR	5,182	
Purchases	943	14.9
Total MCR and Purchases	6,125	100.00

The following table sets forth performance indicators for the Authority's coal-fired generation for the years 2011 through 2013.

	2011	2012	2013
Capacity Factor - %	57.9	45.7	43.6
Availability Factor - %	88.7	94.5	92.5
Forced Outage Rate - %	5.9	2.3	1.8
Net Heat Rate (BTU/kWh)	9,987	9,854	9,999

Performance monitoring systems are in place at the Authority's coal-fired generating stations and at its Rainey Generating Station to optimize each unit's operation while complying with environmental requirements.

All Authority operated units are maintained with computerized maintenance management systems and the use of preventive, predictive, and proactive maintenance practices to achieve high reliability and efficiency at low maintenance cost. In its maintenance program, the Authority utilizes technologies such as vibration analysis, oil analysis, thermography, laser alignment, and non-destructive testing. The Authority continues to implement equipment maintenance programs for the units including major unit components such as control systems, steam generators, and turbine generators. See "CAPITAL IMPROVEMENT PROGRAM."

Summer Nuclear Unit 1. The Authority owns a one-third undivided interest in Summer Nuclear Unit 1 which has a pressurized water reactor with a maximum dependable rating of 954 MW net. SCE&G owns the remaining two-thirds interest and operates and maintains Summer Nuclear Unit 1 on its own behalf and as the Authority's agent.

The following table sets forth certain performance indicators for Summer Nuclear Unit 1 for the years 2011 through 2013 and for the period of commercial operation, January 1, 1984 through December 31, 2013. The next 18 month refueling outage is scheduled to commence on April 4, 2014.

	2011(1)	2012(2)	2013	January 1, 1984-December 31, 2013
Net Generation -- MWh	7,426,233	7,281,603	8,369,878	204,331,133
Capacity Factor -- %	87.8	85.8	98.9	83.6
Availability Factor -- %	87.1	84.9	97.0	85.3
Forced Outage Rate -- %	0.7	0.0	0.0	2.4

(1) Spring 2011 - 45 day for scheduled refueling outage

(2) Fall 2012 - 56 day for scheduled refueling outage

The Nuclear Regulatory Commission (the "NRC") oversees plant performance through the Reactor Oversight Process ("ROP") assessment program. The ROP assessment program collects information from inspections and performance indicators ("PIs") which the NRC uses to objectively assess a facility's safety performance. The ROP consists of three key strategic performance areas: Reactor Safety, Radiation Safety, and Safeguards. Results for inspections and PIs are classified as green, yellow, white or red, with green being the most favorable. Through the first quarter of 2014, Summer Nuclear Unit 1 is in the Licensee Response Column of the ROP Action Matrix because all inspection findings had very low (i.e., green) safety significance, and all PIs indicated that performance was within the nominal, expected range (i.e., green). As a result of being in the Licensee Response Column, NRC oversight of Summer Nuclear Unit 1 is limited to baseline inspections.

In 2004, the NRC extended the operating license for Summer Nuclear Unit 1 to August 6, 2042, which was an additional twenty years.

Under the provisions of the Nuclear Waste Policy Act of 1982, on June 29, 1983 SCE&G and the Authority entered into a contract (the "Standard Contract") with the DOE for spent fuel and high level waste disposal for the operating life of Summer Nuclear Unit 1. The Nuclear Waste Policy Act and the Standard Contract required the DOE to accept and dispose of spent nuclear fuel and high-level radioactive waste beginning not later than January 31, 1998. To date, the DOE has accepted no spent fuel from Summer Nuclear Unit 1 or any other utility, and has not indicated when it anticipates doing so.

Summer Nuclear Unit 1 has licensed on-site spent fuel storage capability until 2017 while still maintaining full core discharge capability. In 2013, construction began on a dry cask storage facility to accommodate the spent nuclear fuel output for the life of Summer Nuclear Unit 1. The dry cask storage facility will be available to receive spent nuclear fuel in 2015.

Unit Retirements. After evaluating the costs of complying with newly adopted federal regulations and the foreseeable generation resource needs for the Authority's system, management determined it would not be cost effective to implement the new environmental measures that would be necessary for continued operation of certain units. In 2012, the Authority's Board of Directors authorized retirement of six electric generating units: Grainger Generating Station Nos. 1 and 2, and Jefferies Generating Station Nos. 1, 2, 3 and 4. The Board authorized the President and CEO to develop and execute plans for an orderly retirement of the four coal and two oil units. Grainger Generating Station Nos. 1 and 2 and Jefferies Generating Station Nos. 3 and 4 ceased operations and were officially retired on December 31, 2012. Appropriate notifications were submitted to the federal Environmental Protection Agency (the "EPA") and The South Carolina Department of Health and Environmental Control (the "DHEC") to modify existing Title V air operating permits to reflect the cease operation of those units. Jefferies Generating Station Nos. 1 and 2 will be retired within a timeline to be determined by the Authority's management and in compliance with applicable regulatory deadlines.

Renewable Energy Power Purchase Agreements. The Authority has purchase power agreements for approximately 25 MW of biogas-fueled energy from multiple facilities within the State. Commercial operations for these facilities are scheduled over the next six years.

Transmission

The Authority operates an integrated transmission system which includes lines owned and leased by the Authority as well as those owned by Central. The transmission system includes approximately 1,265 miles of 230 kilovolt ("kV"), 1,834 miles of 115 kV, 1,733 miles of 69 kV, 10 miles of 46 kV and 97 miles of 34 kV and below overhead and underground transmission lines. The Authority operates 105 transmission substations and switching stations serving 85 distribution substations and 465 Central Cooperative delivery points. Monitoring and control of integrated power system operations is supported by 91 primary communications sites. The Authority plans the transmission system to operate during normal and contingency conditions that are outlined in electric system reliability standards adopted by the North American Electric Reliability Corporation ("NERC") and to maintain system voltages that are consistent with good utility practice.

Interconnections and Interchanges

The Authority's transmission system is interconnected with other major electric utilities in the region. It is directly interconnected with SCE&G at eight locations; with Duke Energy Progress at eight locations; with Southern Company Services, Inc. ("Southern Company") at one location; and with Duke Energy Carolinas, at two locations. The Authority is also interconnected with SCE&G, Duke Energy Carolinas, Southern Company and SEPA through a five-way interconnection at SEPA's J. Strom Thurmond Hydroelectric Project, and with Southern Company and SEPA through a three-way interconnection at SEPA's R. B. Russell Hydroelectric Project. Through these interconnections, the Authority's transmission system is integrated into the regional transmission system serving the southeastern areas of the United States and the Eastern Interconnection. The Authority has separate interchange agreements with each of the companies with which it is interconnected which provide for mutual exchanges of power.

Reliability Agreements

The Authority is a party to the Virginia-Carolinas Reliability Agreement ("VACAR") which exists for the purpose of safeguarding the reliability of electric service of the parties thereto. Other parties to the VACAR agreement are SCE&G, Duke Energy Progress, Duke Energy Carolinas, APGI-Yadkin Division, Dominion Virginia Power, and Public Works Commission of the City of Fayetteville.

The Authority is also a member of the SERC Reliability Corporation, which is one of 8 regional entities under the NERC.

Distribution

The Authority owns distribution facilities in two service areas: the Berkeley District serving retail customers in St. Stephen, Bonneau Beach, Moncks Corner and Pinopolis; and the Horry-Georgetown Division serving retail customers in Conway, Myrtle Beach, North Myrtle Beach, Loris, Briarcliffe, Surfside Beach, Atlantic Beach, Pawleys Island, unincorporated areas along the Grand Strand and portions of rural Georgetown and Horry Counties. See "CUSTOMER BASE."

General Plant

The Authority owns general plant consisting of office facilities; transportation and heavy equipment; computer equipment; and communication equipment necessary to support the Authority's operations. The Authority has nine customer service offices throughout its direct service territory and corporate headquarters located in Moncks Corner which includes a garage, maintenance facilities and warehouse facilities.

Fuel Supply

During 2013, the Authority's energy supply, including energy wheeled to SEPA preference customers, was derived as set forth in the following table.

Source of Power Supply	% of Total (MWh)
Coal	51.1
Natural Gas and Oil	15.8
Nuclear	10.2
Owned Hydro Generation	2.3
Purchases	20.2
Landfill Methane Gas	0.4
Total	100.0

Coal. The Authority has contracted for bituminous coal for its Winyah and Cross Generating Stations from a number of companies, and additional coal is acquired from spot market purchases. All of the Authority's suppliers have loading facilities for providing delivery of coal in unit train shipments. The Authority owns 1,711 coal cars and periodically supplements its fleet with cars provided by the railroad and through short term leases. Currently, the Authority has 216 coal cars on short term lease. The Authority's current rail transportation contract extends through 2015.

The Authority contracts for solid fuel from three primary coal basins: Central Appalachia, Northern Appalachia, and Illinois Basin. Considering quantity and quality requirements, the Authority uses a combination of these coal supplies with long-term and short-term contracts to meet its solid fuel needs. The Authority evaluates the fuel contracts based on the lowest delivered prices while ensuring and adapting to future needs.

The Authority uses a methodology that reflects the impact of coal to gas switching to calculate its coal days on hand. This methodology for calculating coal days on hand uses the annual amount of coal budgeted to be burned divided by 365. The annual burn budget uses projections based on gas prices and forward price curves available at the time the budget is developed and should therefore factor in coal to gas generation switching based on economics. Using this methodology, the Authority had 189 days of coal on hand as of April 30, 2014. In terms of tonnage, as of April 30, 2014, the Authority had approximately 3.65 million tons of coal on hand.

Sulfur dioxide ("SO_2") air emission limitations dictate the maximum amount of coal sulfur content that can be used by generating units. The sulfur content of coal received under existing contracts ranges from approximately 0.9% to 3.0%. The Authority believes it can obtain an adequate coal supply with sulfur content within acceptable ranges to meet foreseeable needs. See "REGULATORY MATTERS -- Environmental Matters."

Gas. The Authority has contracted with Transcontinental Gas Pipeline Corporation to provide firm gas transportation in an amount approximately equal to the Rainey Generating Station combined cycle unit at full load.

Any additional gas transportation necessary to fuel the remaining needs of the simple cycle units at the station will be purchased on the spot market as needed. If gas is unavailable or uneconomical, the Authority will operate the station using fuel oil where possible. The Authority has backup oil storage facilities on site.

The Authority purchases the majority of its natural gas on a daily or short-term basis and does not currently have any purchases under long term agreements. The Authority's natural gas risk is managed using a financial hedge strategy. See "POWER SUPPLY AND POWER MARKETING -- Fuel Supply -- *Commodity Risk Management*." All of the Authority's natural gas transactions are currently executed by TEA.

Commodity Risk Management. The Authority's Board of Directors has approved a policy that deals with the philosophy, framework and delegation of authority necessary to govern the activities related to the Authority's commodity risk management program. The Authority strives to mitigate variations in price with a combination of long-term and short-term contracts, a fuel commodity risk hedging program, and by taking advantage of market opportunities, such as purchasing and blending off-specification coal when the economics are favorable.

The Authority has determined that all transactions executed under the policy will be executed through TEA.

Nuclear. Under the Joint Ownership Agreement for Summer Nuclear Unit 1, SCE&G acts for itself and as agent for the Authority in the operation of Summer Nuclear Unit 1 including the acquisition and management of nuclear fuel. Contracts are in place to supply uranium and conversion through 2020. Enrichment services will be met by contract through 2024.

The Energy Authority

The Authority is a member of TEA along with City Utilities of Springfield (Missouri), Gainesville Regional Utilities (Florida), Jacksonville Energy Authority ("JEA"), Municipal Electric Authority of Georgia ("MEAG Power"), Nebraska Public Power District ("NPPD"), Public Utility District No. 1 of Cowlitz County, Washington and American Municipal Power.

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 its members. TEA is expected to accomplish the foregoing without impacting the safety and reliability of the electric system of each member. In addition, TEA purchases and sells natural gas relating to fuel for members' generation of electricity. TEA does not engage in the construction or ownership of generation or transmission assets.

The standards of conduct provisions of Order 717 of the Federal Energy Regulatory Commission (the "FERC") require that employees of a utility engaged in transmission system operations function independently of employees of the utility or any of its affiliates who are engaged in the wholesale merchant function. The Authority believes that the establishment of TEA assists in satisfying that requirement.

All of TEA's revenues and its costs are allocated to its members. The Authority's exposure relating to TEA is limited to the Authority's capital investments in TEA, any accounts receivable from TEA and trade guarantees provided to TEA by the Authority.

The current amount approved by the Authority to support TEA's trading and procurement activities is an amount not to exceed approximately $72.9 million. If payment is required to be made, it will be treated as an operation and maintenance expense.

Colectric Partners

The Authority is also a member of Colectric Partners ("Colectric"). Colectric's member participants are: the Authority, Florida Municipal Power Agency, Gainesville Regional Utilities, JEA, MEAG Power, NPPD and Orlando Utilities Commission.

Colectric is a membership-driven nonprofit corporation headquartered in Jacksonville, Florida which serves the public power industry in a variety of project and business management roles. They help their members leverage economies of scale to control operations and maintenance costs and streamline power generation projects.

Currently, the Authority participates in two of Colectric's initiatives. The first involves managing the major gas turbine overhauls, thereby promoting the sharing of spare parts and technical expertise. The second initiative is a strategic sourcing initiative, intended to achieve major cost savings through volume purchasing leverage.

CAPITAL IMPROVEMENT PROGRAM

General

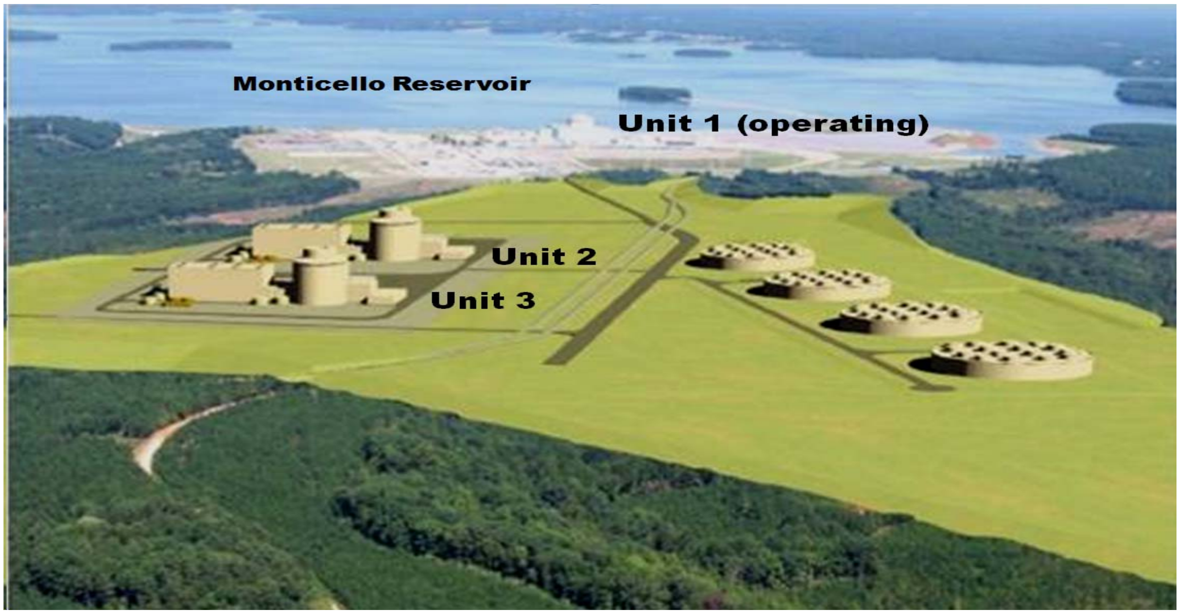
The Authority regularly reviews and updates its capital improvement program to reflect currently projected capital projects and expenditures. Total cost of the capital improvement program for 2014 through 2016 is estimated to be approximately $2,724,000,000, which includes approximately $2,056,000,000 for Summer Nuclear Units 2 and 3 based on 45% ownership, approximately $167,000,000 for environmental compliance expenditures, and approximately $501,000,000 for general improvements to the System. See "FINANCING PLAN FOR SUMMER NUCLEAR UNITS 2 AND 3" for further details. The Authority typically finances generation resources and large capital projects with long-term borrowed funds while utilizing the capital improvement fund for other resources such as general improvements to the System and equity to reduce taxable borrowings. The cost of the capital improvement program will be provided from Revenues of the Authority, additional Revenue Obligations, and Commercial Paper Notes and other short-term obligations of the Authority, as determined by the Authority.

Long-Term Power Supply Plan

The Authority's overall power supply objective is to continue to satisfy the electric power and energy needs of its customers with economical and reliable service. As part of this objective the Authority strives to have in place a diverse power supply that utilizes a variety of fuel sources. The Authority reviews, from time to time, its power resources and requirements and considers the need for the possible addition of new power resources, the retirement of existing resources and other modifications to its resource plan. In January 2008, the Authority's Board of Directors approved a generation resource plan that included, among other things, a 45% ownership interest in Summer Nuclear Units 2 and 3. At a 45% ownership, these units are projected to increase the percentage of power generated from nuclear resources from approximately 10% to approximately 40% after both units are completed. Nuclear power stations have higher capital costs, but they have very low fuel costs, which have already proven to be stable and competitive, to balance out the capital expense. Nuclear power is an emissions free, non-greenhouse gas emitting resource and, therefore is not subject to regulation and legislation typically associated with fossil fired resources such as those targeting carbon and SO_2 emissions.

The Authority has evaluated its capital improvement program and long-term power supply plan in light of the on-going economic downturn, the reduction in previously anticipated sales to Central, as described under "CUSTOMER BASE - Wholesale," and new EPA regulations which increase the operating costs of coal-fired generating units as described under "REGULATORY MATTERS -- Environmental Matters." As a result, the Authority will retire six electric generating units (See "POWER SUPPLY AND POWER MARKETING-- Existing Power Resources") and has entered into an agreement whereby SCE&G would purchase an additional 5% in Summer Nuclear Units 2 and 3. Under the terms of the agreement, SCE&G will own 60% of the new nuclear units and the Authority, 40%. See CAPITAL IMPROVEMENT PROGRAM -- Summer Nuclear Units 2 and 3."

Summer Nuclear Units 2 and 3

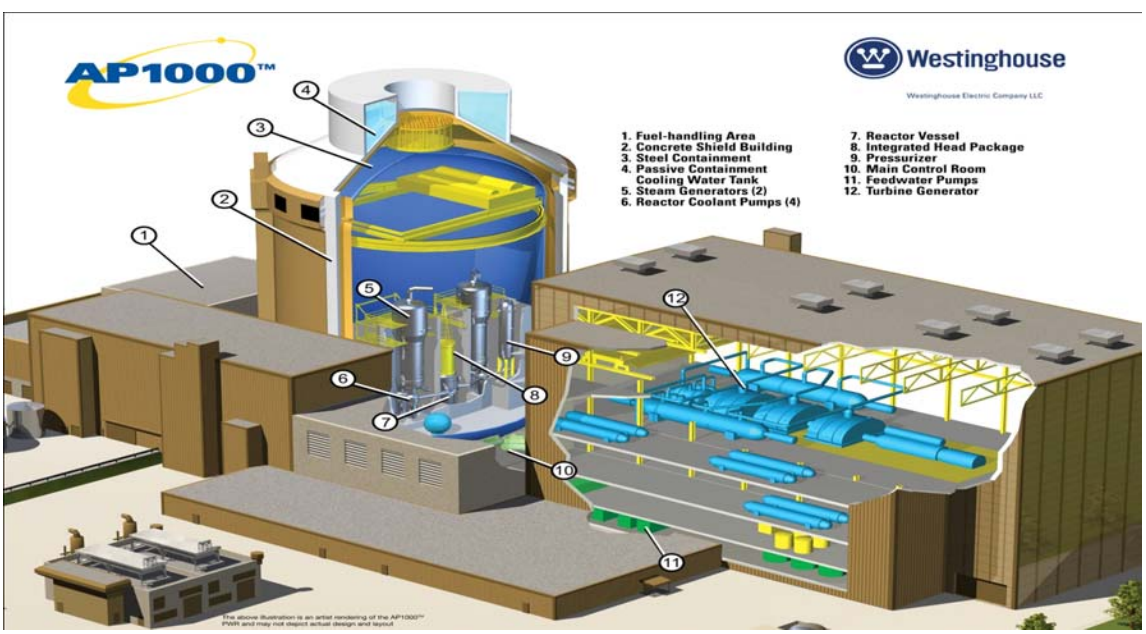


Technology. Summer Nuclear Units 2 and 3 will consist of two Westinghouse AP1000 nuclear reactors, four low profile sixteen-cell mechanical draft cooling towers, intake and discharge structures, a 230 kV switchyard for transmission access, and numerous ancillary structures supporting the power generation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

In January, 2014, the Authority's negotiations with Duke Energy Carolinas to purchase a portion of the Authority's ownership interest in Summer Nuclear Units 2 and 3 terminated. Subsequently, the Authority entered into an agreement whereby SCE&G would purchase an additional 5% in the units. Under the terms of the agreement, SCE&G will own 60% of the new nuclear units and the Authority, 40%. The 5% ownership interest would be acquired in three stages, with 1% to be acquired at the commercial operation date of the first new nuclear unit, which is anticipated to be in mid-2018, 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 would be equal to the Authority's actual cost, including financing costs, of the percentage conveyed as of the date of the conveyance. The Authority is exploring opportunities to market capacity from the units to potential buyers.

Construction - Phase I. Phase I of the work consists 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.

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

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 pre-fabricated 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.

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 is 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 is expected to be similarly delayed.

Since August 2013, the Consortium has experienced additional delays in sub-module fabrication and deliveries. The fabrication and delivery of sub-modules 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 fourth quarter of 2014. In response to these additional delays, SCE&G and the Authority are actively working with Consortium executive management to take actions necessary to minimize changes to the substantial completion dates announced in June 2013.

In addition to the above-described project delays, the Authority is also aware of financial difficulties a supplier responsible for certain significant components of the project is experiencing. The Consortium is monitoring the potential for disruptions in such equipment fabrication and possible responses. Any disruptions could impact the project's schedule or costs, and such impacts could be material.

During the fourth quarter of 2013, the Consortium began a full re-baselining of the Unit 2 and Unit 3 construction schedules to incorporate a more detailed evaluation of the engineering and procurement activities necessary to accomplish the schedule and to provide a detailed reassessment of the impact of the revised Unit 2 and Unit 3 schedules on engineering and design resource allocations, procurement schedules, construction work crew assignments, and other items. The result will be a revised fully integrated construction schedule that will provide detailed and itemized information on individual budget and cost categories, cost estimates at completion for all non-firm and fixed scopes of work, and the timing of specific construction activities and cash flow requirements. The Authority anticipates that the revised schedule and the cost estimate at completion for all non-firm and fixed scopes of work will be finalized in the third quarter of 2014. The Authority cannot predict with certainty the extent to which the issue of sub-module fabrication and deliveries will impact project costs or the anticipated re-baselined schedule. However, the Authority and SCE&G have not accepted financial responsibility for any project cost impacts associated with delayed sub-module fabrication and deliveries.

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.

HISTORICAL SALES

Historical Demand, Sales and Revenues

The following table sets forth the territorial peak demand including firm off-system sales to other utilities, if any, on the Authority's System as well as the million kWh ("GWh") sales and electric revenues of the Authority for the years 2004 through 2013.

	Peak Demand(1)		Sales		Revenue From Sales		
	MW	Annual Increase (Decrease)	GWh	Annual Increase (Decrease)	Amount (Dollars in Thousands)	Annual Increase (Decrease)	Cents Per kWh
2004	5,111	(5.3)	24,451	1.6	1,136,042	9.9	4.65
2005	5,393	5.5	25,064	2.5	1,334,057	17.5	5.33
2006	5,218	(3.2)	25,422	1.4	1,396,252	4.6	5.49
2007	5,584	7.0	27,221	7.1	1,448,327	3.7	5.32
2008	5,672	1.6	26,687	(2.0)	1,568,618	8.3	5.88
2009	5,612	(1.1)	25,813	(3.3)	1,683,469	7.3	6.52
2010	5,762	2.7	28,182	9.2	1,875,263	11.4	6.65
2011	5,697	(1.1)	27,552	(2.2)	1,894,847	1.0	6.88
2012	5,407	(5.1)	26,756	(2.9)	1,868,808	(1.4)	6.98
2013	5,053	(6.6)	26,364	(1.5)	1,796,672	(3.9)	6.81
Annual Compound Growth Rate (2004-2013)		(0.1)		0.8		5.2	

(1) Includes firm off-system sales to other utilities.

The following tables set forth sales and revenues by customer class for the years 2009 through 2013.

Sales (GWh)

Class of Customers	2009	% of Total	2010	% of Total	2011	% of Total	2012	% of Total	2013	% of Total
Wholesale	15,607	60.5	17,231	61.1	16,263	59.0	15,604	58.3	15,246	57.8
Large Industrial	6,501	25.2	6,953	24.7	7,443	27.0	7,509	28.1	7,421	28.1
Residential, Commercial, Small Industrial and Other .	3,705	14.3	3,998	14.2	3,845	14.0	3,643	13.6	3,697	14.1
Total	25,813	100.0	28,182	100.0	27,551	100.0	26,756	100.0	26,364	100.0

Revenues (Dollars in Thousands)

Class of Customers	2009	% of Total	2010	% of Total	2011	% of Total	2012	% of Total	2013	% of Total
Wholesale	$ 1,028,193	61.1	$1,142,582	60.9	$1,129,445	59.6	$1,144,223	61.2	$1,058,943	58.9
Large Industrial	346,318	20.6	376,247	20.1	415,309	21.9	389,742	20.9	381,689	21.2
Residential, Commercial, Small Industrial and Other .	308,958	18.3	356,435	19.0	350,093	18.5	334,843	17.9	356,040	19.9
Total	$1,683,469	100.0	$1,875,264	100.0	$1,894,847	100.0	$1,868,808	100.0	$1,796,672	100.0

FINANCIAL INFORMATION

Historical Operating Results

A summary of the Authority's revenues available for debt service, lease payments and other purposes for years 2009 through 2013 is set forth below:

	Calendar Year (Dollars in Thousands)				
	2013	2012	2011	2010	2009
Operating Revenues	$1,816,576	$1,887,797	$1,914,689	$1,894,902	$1,702,001
Other Income(1)	9,246	9,025	8,081	126	3,946
Total	1,825,822	1,896,822	$1,922,770	$1,895,028	$1,705,947
Operating Expenses(2)	1,327,370	1,379,158	1,366,423	1,318,814	1,201,140
Revenues Available for Debt Service, Lease Payments and Other Purposes	498,452	517,664	556,347	576,214	504,807
Debt Service on Revenue Bonds(3)	0	0	0	0	3,298
Balance Available for Revenue Obligations, Lease Payments and Other Purposes	498,452	517,664	556,347	576,214	501,509
Debt Service on Revenue Obligations(4)	325,402	356,852	342,621	362,506	339,875
Balance Available for Lease Payments and Other Purposes	173,050	160,812	213,726	213,708	161,634
Debt Service on Lease Payments	939	1,346	1,559	1,936	2,664
Balance Available for Other Purposes	$ 172,111	$ 159,466	$ 212,167	$ 211,772	$ 158,970
Debt Service Coverage(5):					
Revenue Bonds, Revenue Obligations and Lease Payments	1.52	1.44	1.61	1.58	1.45

(1) Includes interest subsidy payments for the 2010 Build America Bonds ("BABS"). Years 2009 through 2012 exclude gains on sale of leased lots or rail cars.

(2) Year 2013 excludes depreciation only. Years 2009 through 2012 exclude depreciation and sums in lieu of taxes paid by Special Reserve Fund.

(3) This category of bonds is no longer outstanding.

(4) The Revenue Obligation Resolution provides for debt service of Revenue Obligations to be paid from Revenues prior to payments for operating and maintenance expenses. See "SECURITY FOR THE 2014M1 BONDS - Rate Covenant."

(5) Calculation of coverage does not include debt service on Commercial Paper Notes and Other.

REGULATORY MATTERS

The Electric Utility Industry Generally

The electric utility industry in general has been affected by regulatory changes, market developments and other factors which have impacted, and will probably continue to impact, the financial condition and competitiveness of electric utilities and the level of utilization of facilities, such as those of the Authority. Such factors include, among others, (a) effects of compliance with rapidly changing environmental, safety, licensing, regulatory and legislative requirements, (b) changes resulting from conservation and demand-side management programs on the timing and use of electric energy, (c) changes that might result from national energy policies, (d) effects of competition from other electric utilities (including increased competition resulting from mergers, acquisitions, and strategic alliances of competing electric (and gas) utilities and from competitors transmitting less expensive electricity from much greater distances over an interconnected system) and new methods of producing low cost electricity, (e) increased competition from independent power producers, marketers and brokers, (f) self-generation by certain industrial, commercial and residential customers, (g) issues relating to the ability to issue tax-exempt obligations, (h) restrictions on the ability to sell to nongovernmental entities electricity from projects financed with outstanding tax-exempt obligations, (i) changes from projected future load requirements, (j) increases in costs, and (k) shifts in the availability and relative costs of different fuels. Any of these factors (as well as other factors) could have an effect on the financial condition of any given electric utility, including the Authority, and likely will affect individual utilities in different ways.

The Authority cannot determine with certainty what effects such factors will have on its business operations and financial condition, but the effects could be significant. Extensive information on the electric utility industry is available from sources in the public domain, and potential purchasers of the 2014M1 Bonds should obtain and review such information.

Environmental Matters

Both the EPA and the DHEC have imposed various environmental regulations and permitting requirements affecting the Authority's facilities. These regulations and requirements relate primarily to airborne pollution, the discharge of pollutants into waters and the disposal of solid and hazardous wastes. The Authority endeavors to ensure its facilities comply with applicable environmental regulations and standards; however, no assurance can be given that normal operations will not encounter occasional technical difficulties or that necessary permits and authorizations will be received. Federal and state standards and procedures that govern control of the environment and systems operations can change. These changes may arise from legislation, regulatory action, and judicial interpretations regarding the standards, procedures and requirements for compliance and issuance of permits. Therefore there is no assurance that units in operation, under construction, or contemplated will remain subject to the regulations that are currently in effect. Furthermore, changes in the clean air laws and environmental standards may result in increased capital and operating costs.

Air Quality

General Regulatory Requirements. The Authority is subject to a number of federal and state laws and regulations which address air quality. Pursuant to the Clean Air Act ("CAA"), as amended, the EPA promulgated primary and secondary national ambient air quality standards ("NAAQS") with respect to certain air pollutants, including particulate matter, SO_2 and nitrogen oxide ("NO_x"). These standards are to be achieved by the application of control strategies developed by the states and included in implementation plans which must be approved by the EPA to become effective. DHEC has adopted a State Implementation Plan ("SIP"), which has been approved by the EPA, generally designed to achieve the primary and secondary air quality standards. The EPA also promulgated the New Source Performance Standards ("NSPS") regulations establishing stringent emission standards for particulate matter, SO_2 and NO_x emissions for fossil-fuel fired steam generators, and revised these standards in 1979 and 2005. Congress has enacted comprehensive amendments to the 1990 CAA, including the addition of a new federal Acid Rain program to deal with acid precipitation.

Evolving Regulatory Requirements

Clean Air Interstate Rule and Cross State Air Pollution Rule. The federal Clean Air Interstate Rule (the "CAIR"), which addresses NO_x and SO_2 emissions, took effect July 11, 2005. The EPA issued a final replacement to the CAIR rule, the Cross-State Air Pollution Rule ("CSAPR"), on July 6, 2011, which was scheduled to take effect January 1, 2012. On

December 30, 2011 the U.S. Court of Appeals for the D.C. Circuit issued its ruling to stay the CSAPR pending judicial review. On August 21, 2012, the U.S. Court of Appeals for the D.C. Circuit issued its ruling vacating CSAPR. The EPA appealed the Court's ruling but the appeal was denied by the U.S. Court of Appeals for the D.C. Circuit. The EPA appealed the U.S. Court of Appeals decision to the U.S. Supreme Court. On April 29, 2014, the U.S. Supreme Court reversed the Court of Appeals and remanded the case to the D.C. Circuit for further action. CAIR remains in effect until the D.C. Circuit acts to implement CSAPR rule. The Authority is in compliance with CAIR and expects its existing units could comply with CSAPR without any significant capital improvements.

Mercury and Air Toxics Standard. Over the last several years EPA has been evaluating appropriate Maximum Achievable Control Technology ("MACT") standards for source categories and proposing various regulatory programs for mercury control for power plants. On April 16, 2012, the final rule, renamed the Mercury and Air Toxics Standard ("MATS"), became effective with a compliance deadline of April 16, 2015. Although somewhat less stringent than the earlier proposed MACT rule, MATS will have significant impacts on the Authority's coal-fired units. The Authority has evaluated the impact of this rule to its existing coal-fired fleet has estimated the capital costs for compliance not to exceed $55 million.

Greenhouse Gases. In March, 2012, the EPA proposed NSPS for emissions of carbon dioxide ("CO_2") for new affected fossil fuel-fired electric utility generating units ("EGUs"). The EPA proposed these requirements because CO_2 is a greenhouse gas ("GHG") and fossil fuel-fired power plants are the country's largest anthropogenic stationary source emitters of GHGs. The EPA in 2009 found that by causing or contributing to climate change, GHGs endanger both the public health and the public welfare of current and future generations. The proposed requirements, which are strictly limited to new sources, would require new fossil fuel-fired EGUs greater than 25 megawatt electric to meet an output-based standard of 1,000 pounds of CO_2 per megawatt-hour, based on the performance of widely used natural gas combined cycle technology. This limit essentially precludes the construction of new coal fired generation without CO_2 controls, such as carbon capture and sequestration.

On September 22, 2009, the EPA announced a final rule on the new GHG reporting program. This rule is commonly referred to as the Greenhouse Gas Mandatory Reporting Rule ("GHG-MRR"). Beginning January 1, 2010, the Authority was required to annually report GHG emissions data to the EPA for any of its facilities that emit 25,000 metric tons or more of CO_2 or equivalent per year. This reporting requirement applies to the Authority's larger generating facilities, and electrical transmission and distribution equipment. The Authority has filed annual reports in compliance with this requirement.

The EPA and Congress continue to consider strong measures that will reduce GHG emissions from major sources, including electric utilities, as well as implementation of other complementary measures to reduce GHG emissions. In a June 25, 2013 memorandum, President Obama directed the EPA to repropose its NSPS for GHGs for new power plants by September 20, 2013 and to propose standards, regulations, or guidelines, as appropriate, by June 1, 2014, for existing, reconstructed or modified plants. The memo directed the EPA to issue final rules or guidelines for existing plants by June 1, 2015. On January 8, 2014 the EPA published in the Federal Register the proposed CO_2 NSPS for GHGs for new power plants, with comments due May 9, 2014. The Authority submitted comments to the EPA as it relates to potential new generation for the Authority's fleet. The potential cost impact of future GHG regulation or legislation could be significant and the Authority will continue to monitor regulatory and legislative developments.

Water Quality

General Regulatory Requirements. The Authority is subject to a number of federal and state laws and regulations which address water quality. 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. The DHEC has been delegated NPDES permitting authority by the EPA and administers the program for the State. Industrial wastewater discharges from all stations and the regional water plants are governed by NPDES permits. The DHEC also has permitting authority for stormwater discharges and the Authority manages stormwater pursuant to the DHEC issued Industrial General Permits and Construction General Permits.

Evolving Regulatory Requirements

316(b) Fish Protection Regulations. Section 316(b) of the CWA requires that NPDES permits for facilities with cooling water intake structures ensure that the structures reflect the best technology available to minimize adverse environmental impacts from impingement and entrainment of fish and egg larvae. The EPA published a draft rule in the Federal Register on April 20, 2011. Compliance dates range from six months to eight years for various components of the rule and are geared to the time the EPA issues the final rule. The final rule is anticipated in May 2014. The Authority has reviewed the draft rule to determine the potential impact to the Authority's applicable generating facilities, which are Jefferies (Units 1 & 2), Cross, Winyah, and Rainey. The Authority has estimated and budgeted for an estimated cost of compliance based on the draft rule and current estimates are approximately $7.8 million through 2024.

Effluent Limitation Guidelines. On April 19, 2013, the EPA released a proposed rulemaking pursuant to section 304(b) of the CWA establishing effluent limitation guidelines ("ELGs") for all steam electric generating units. The final rule is anticipated in late 2014. Implementation of the rule will require generating units to comply with specific effluent limitations, based upon the availability and cost of applicable pollution control technology. The guidelines propose stricter performance standards that will require upgrades and installation of additional wastewater treatment systems for certain facilities including Winyah and Cross Generating Stations. EPA sets the ELG limits based on their evaluation of the "best available" treatment technologies that the EPA believes are economically achievable. The Authority is evaluating the proposed rule and has provided comments. The Authority cannot fully estimate the potential cost of compliance with the proposed rule.

Solid and Hazardous Waste and Hazardous Substances

General Regulatory Requirements. The Authority is subject to a number of federal and state laws and regulations which address hazardous substances and wastes. These include the CWA, which imposes substantial penalties for spills of oil or 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") which provides for the reporting requirements to cover the release of hazardous substances generally into the environment, including water, land and air, and imposes liability upon any generators, transporters or arrangers of disposal of hazardous substances, and the CERCLA and Superfund Amendments and Reauthorization Act ("SARA"), which require compliance with programs for emergency planning and public information. Additionally, the EPA regulations under the Toxic Substances Control Act impose stringent requirements for labeling, handling, storing and disposing of polychlorinated biphenyls ("PCB") and associated equipment. There are regulations covering PCB notification and manifesting, restrictions on disposal of drained electrical equipment, spill cleanup record-keeping requirements, etc. The Authority has a comprehensive PCB management program in response to these regulations.

Evolving Regulatory Requirements

Solid Waste – Coal Combustion Residual Rule. In addition to handling hazardous substances, 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 Resource Conservation and Recovery Act ("RCRA"). However, in 2010, the EPA issued a proposed rule to regulate CCRs under RCRA. The proposed rule provides two options for regulation of the CCRs. One option is to regulate the CCRs as a RCRA Subtitle C, hazardous waste, and the other is to regulate the CCRs as a RCRA Subtitle D, non-hazardous waste. The proposed rule could impact beneficial reuse of CCRs as a non-hazardous waste byproduct and could impact the Authority's method of management of CCRs with regard to the coal fired units in operation at Cross and Winyah and the recently retired coal fired units at Grainger and Jefferies. No firm estimates relative to the cost of implementing this draft regulation, when promulgated, can be made at this time since the final outcome of the rule is uncertain, however, the Authority has budgeted $320 million through 2019 for compliance purposes. A consent decree filed in US District Court for the District of Columbia on January 29, 2014 requires EPA to publish notice of a final action by December 19, 2014.

Industrial Solid Waste Landfills. 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. 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.

Drinking Water

The Authority continues to monitor for Safe Drinking Water Act 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 the State. The State Primary Drinking Water Regulation, R.61-58, governs the design, construction and operational management of all potable water systems in the State subject to and consistent with the requirements of the Safe Drinking Water Act and the implementation of federal drinking water regulations.

FERC Hydro Licensing

The Authority operates its Jefferies Hydro Station and certain other property, including the Pinopolis Dam on the Cooper River and the Santee Dam on the Santee River, which are major parts of the Authority's integrated hydroelectric complex, under a license issued by the FERC pursuant to the Federal Power Act ("FPA"). The project is currently undergoing relicensing and a Notice of Intent ("NOI") to relicense was filed with the FERC on November 13, 2000. The final license application was submitted March 12, 2004. Due to a number of Additional Information Requests, the relicensing process has extended beyond the license expiration date. The FERC has issued a standing annual license renewal until a final license is issued.

The FERC issued its Final Environmental Impact Statement ("EIS") in October, 2007. The South Carolina Department of Natural Resources, the U.S. Fish and Wildlife Service, and the Authority have jointly signed and filed a settlement agreement with the FERC that among other things, identifies fish passage and outflow guidelines during the term of the next license. The National Marine Fisheries Service ("NMFS") chose not to join in the settlement agreement and has submitted mandatory fishway conditions under §18 of the FPA and flow recommendations under §10 of that Act that are inconsistent with the settlement agreement.

In November 2007, FERC requested that NMFS undertake an Endangered Species Act ("ESA") Section 7 consultation with regard to the relicensing project. In July of 2010, as a function of the required Section 7 consultation, NMFS submitted a draft biological opinion containing recommendations for the endangered shortnose sturgeon. The recommendations, if adopted, would result in substantial additional costs for operating the project. The Authority provided a response to those recommendations in September 2010. The Authority cannot predict when NMFS will issue a final biological opinion or the final outcome of the FERC relicensing process.

NERC Regulation

The NERC establishes and enforces reliability standards, including critical infrastructure protection standards, for the bulk power system. The critical infrastructure protection standards focus on controlling access to critical physical and cyber security assets. Compliance with these standards is mandatory. The maximum penalty that may be levied for violating a NERC reliability standard is $1 million per violation, per day. The Authority has self-reported some violations of NERC reliability or critical infrastructure protections standards and paid the necessary fines. The Authority has formal programs, processes, and policies in place to promote compliance with these standards. However, it is not possible to predict whether the Authority will have future violations or what the fines for such violations might be.

Nuclear Matters

Summer Nuclear Unit 1 is subject to regulation by the NRC. SCE&G and the Authority were required to obtain liability insurance and a United States Government indemnity agreement for Summer Nuclear Unit 1 in order for the NRC operating license to be issued. This primary insurance and the retrospective assessment are to insure against the maximum liability under the federal Price-Anderson Act for any public claims arising from a nuclear incident. The Energy Policy Act of 2005 extends the Price-Anderson Act until 2025.

The NRC requires that a licensee of a nuclear reactor 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 to comply with the new regulations. The Authority began making deposits into the external decommissioning fund in September 1990.

In addition to providing for the minimum requirements imposed by the NRC, the Authority established in 1983 an internal decommissioning fund. Based on the most recent decommissioning cost estimates developed by SCE&G, both the internal and external funds, which had a combined market value of approximately $185 million at December 31, 2013, along with future deposits into the external trust and investment earnings, are estimated to provide sufficient funds for the Authority's one-third share of the total estimated decommissioning costs.

Potential Nuclear Plant Guidelines. In March 2011, a major earthquake and tsunami struck Japan and caused substantial damage to the nuclear generating units at the Fukushima Daiichi generating plant. The events in Japan have created uncertainties that may affect future costs for operating nuclear plants. Specifically, the NRC is performing additional operational and safety reviews of nuclear facilities in the U.S., which could potentially impact future operations and capital requirements. On March 12, 2012, the NRC issued three orders and a request for information based on the July 2011 NRC task force report recommendations that included, among other items, additional mitigation strategies for beyond-design-basis events, enhanced spent fuel pool instrumentation capabilities, hardened vents for certain classes of containment structures, site specific evaluations for seismic and flooding hazards, and various plant evaluations to ensure adequate coping capabilities during station blackout and other conditions. On August 29, 2012, the NRC staff issued the final interim staff guidance document, which offers acceptable approaches to meeting the requirements of the NRC's orders before the December 31, 2016 compliance deadline. The interim staff guidance is not mandatory, but licensees would be required to obtain NRC approval for taking an approach other than as outlined in the interim staff guidance. The final form and the resulting impact of any changes to safety requirements for nuclear reactors will be dependent on further review and action by the NRC and cannot be determined at this time; however, management does not currently anticipate that the associated compliance costs would have a material impact on the Authority's financial statements.

LITIGATION

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 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 in the amount of $234,865,797.11 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. The Authority cannot predict the outcome of the appeal.

Grainger Ash Pond Litigation. In June 2012, several environmental advocacy groups filed suit against the Authority in the Court of Common Pleas in Horry County seeking injunctive relief with regard to closure of ash ponds at the Grainger Generating Station. The suit did not seek damages but alleged that an unlawful discharge of arsenic and other contaminants had occurred and requested that the court order the removal and offsite storage of all ash contained in the ponds. In April 2013, an environmental advocacy group filed suit against the Authority alleging that violations of the federal CWA had occurred at Grainger Generating Station. The suit did not seek damages but made claims for injunctive relief, civil penalties and costs and attorney's fees. The Authority settled both suits in November 2013. The settlement did not require the Authority to make any payments to the litigants. The Authority intends to properly close the ash ponds by excavation and beneficial use of the ash in accordance with regulatory requirements.

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. The Authority has been informed that a settlement, subject to court approval, has been reached in the underlying class action lawsuit against Horry Co-op. The settlement provides for the establishment of two funds, totaling $6 million dollars, to pay the claims of the class members. The Authority has filed a motion to dismiss the claims brought against it by Horry Co-op. The Authority intends to vigorously defend the lawsuit but cannot predict the outcome.

FINANCIAL ADVISOR

The Authority has retained Public Financial Management, Inc., as Financial Advisor in connection with the issuance of the 2014M1 Bonds.

TAX MATTERS

The 2014M1 Bonds

Federal Income Tax Generally. On the date of issuance of the 2014M1 Bonds, Haynsworth Sinkler Boyd, P.A., Charleston, South Carolina ("Bond Counsel"), will render an opinion that, assuming continuing compliance by the Authority with the requirements of the Internal Revenue Code of 1986, as amended (the "Code"), and the applicable regulations promulgated thereunder (the "Regulations") and further subject to certain considerations described in "Collateral Federal Tax Considerations" below, under existing statutes, regulations and judicial decisions, interest on the 2014M1 Bonds is excludable from the gross income of the registered owners thereof for federal income tax purposes. Interest on the 2014M1 Bonds will not be treated as an item of tax preference in calculating the alternative minimum taxable income of individuals or corporations; however, interest on the 2014M1 Bonds will be included in the calculation of adjusted current earnings in determining the alternative minimum tax liability of corporations. The Code contains other provisions that could result in tax consequences, upon which no opinion will be rendered by Bond Counsel, as a result of (i) ownership of the 2014M1 Bonds or (ii) the inclusion in certain computations of interest that is excluded from gross income.

The opinion of Bond Counsel will be limited to matters relating to the authorization and validity of the 2014M1 Bonds and the tax-exempt status of interest on the 2014M1 Bonds as described herein. Bond Counsel makes no statement regarding the accuracy and completeness of this Official Statement.

The opinion of Bond Counsel is based on current legal authority, covers certain matters not directly addressed by such authorities, and represents Bond Counsel's judgment as to the proper treatment of the 2014M1 Bonds for federal income tax purposes. Bond Counsel's opinions are based upon existing law, which is subject to change. Such opinions are further based on factual representations made to Bond Counsel as of the date thereof. Bond Counsel assumes no duty to update or supplement its opinions to reflect any facts or circumstances that may thereafter come to Bond Counsel's attention or to reflect any changes in law that may thereafter occur or become effective. Moreover, Bond Counsel's opinions are not a guarantee of a particular result, and are not binding on the IRS or the courts; rather, such opinions represent Bond Counsel's professional judgment based on its review of existing law, and in reliance on the representations and covenants that it deems relevant to such opinions.

The opinion of Bond Counsel described above is subject to the condition that the Authority comply with all requirements of the Code and the Regulations, including, without limitation, certain limitations on the use, expenditure and investment of the proceeds of the 2014M1 Bonds and the obligation to rebate certain earnings on investments of proceeds to the United States Government, that must be satisfied subsequent to the issuance of the 2014M1 Bonds in order that interest thereon be, or continue to be, excludable from gross income for federal income tax purposes. The Authority has covenanted to comply with each such requirement. Failure to comply with certain of such requirements may cause the inclusion of interest on the 2014M1 Bonds in gross income for federal income tax purposes retroactive to the date of issuance of the 2014M1 Bonds. The opinion of Bond Counsel delivered on the date of issuance of the 2014M1 Bonds is conditioned on compliance by the Authority with such requirements, and Bond Counsel has not been retained to monitor compliance with the requirements subsequent to the issuance of such 2014M1 Bonds.

Collateral Federal Tax Considerations. Prospective purchasers of the 2014M1 Bonds should be aware that ownership of tax-exempt obligations may result in collateral federal income tax consequences to certain taxpayers, including, without limitation, financial institutions, property and casualty insurance companies, life insurance companies, certain foreign corporations, certain S corporations, individual recipients of Social Security or Railroad Retirement benefits and taxpayers who may be deemed to have incurred or continued indebtedness to purchase or carry tax-exempt obligations. The 2014M1 Bonds are not "qualified tax-exempt obligations" under Section 265(b)(3) of the Code. Bond Counsel expresses no opinion concerning such collateral income tax consequences, and prospective purchasers of 2014M1 Bonds should consult their tax advisors as to the applicability thereof.

Future legislation, if enacted into law, or clarification of the Code may cause interest on the 2014M1 Bonds to be subject, directly or indirectly, to federal income taxation, or otherwise prevent owners from realizing the full current benefit of the tax status of such interest. The introduction or enactment of any such future legislation or clarification of the Code may also affect the market price for, or marketability of, the 2014M1 Bonds. No prediction can be made concerning future legislation which if passed might adversely affect the tax treatment of interest on the 2014M1 Bonds. Prospective purchasers of the 2014M1 Bonds should consult their own tax advisors regarding any pending or proposed federal tax legislation, as to which Bond Counsel expresses no opinion.

The IRS has established an ongoing program to audit tax-exempt obligations to determine whether interest on such obligations is includable in gross income for federal income tax purposes. Bond Counsel cannot predict whether the IRS will commence an audit of the 2014M1 Bonds. Bond Counsel's engagement with respect to the 2014M1 Bonds ends with the issuance of the 2014M1 Bonds and unless separately engaged, Bond Counsel is not obligated to defend the Authority or the owners of 2014M1 Bonds regarding the tax-exempt status of the 2014M1 Bonds in the event of an audit examination by the IRS. The IRS has taken the position that, under the standards of practice before the IRS, Bond Counsel must obtain a waiver of a conflict of interest to represent an issuer in an examination of tax exempt bonds for which Bond Counsel had issued an approving opinion. Under current procedures, parties other than the Authority and their appointed counsel, including the owners of 2014M1 Bonds, would have little, if any, right to participate in the audit examination process. Moreover, because achieving judicial review in connection with an audit examination of tax-exempt bonds is difficult, obtaining an independent review of IRS positions with which the Authority legitimately disagrees, may not be practicable. Any action of the IRS, including but not limited to selection of the 2014M1 Bonds for audit, or the course or result of such audit, or an audit of bonds presenting similar tax issues may affect the market price for, or the marketability of, the 2014M1 Bonds, and may cause the Authority or the owners of 2014M1 Bonds to incur significant expense, regardless of the ultimate outcome.

State Tax Exemption

Bond Counsel is of the further opinion that the 2014M1 Bonds and the interest thereon are exempt from all taxation by the State of South Carolina, its counties, municipalities and school districts except estate, transfer or certain franchise taxes. Interest paid on the 2014M1 Bonds is currently subject to the tax imposed on banks by Section 12-11-20, Code of Laws of South Carolina 1976, as amended, which is enforced by the South Carolina Department of Revenue and Taxation as a franchise tax. The opinion of Bond Counsel is limited to the laws of the State of South Carolina and federal tax laws. No opinion is rendered by Bond Counsel concerning the taxation of the 2014M1 Bonds or the interest thereon under the laws of any other jurisdiction.

APPROVAL OF LEGAL PROCEEDINGS

Haynsworth Sinkler Boyd, P.A., Charleston, South Carolina, Bond Counsel to the Authority, will render an opinion with respect to the validity and tax treatment of the 2014M1 Bonds. Such opinion will be attached to the 2014M1 Bonds and will be in substantially the form set forth in Appendix III. Certain legal matters will be passed upon on behalf of the Authority by James E. Brogdon, Jr., its Executive Vice President and General Counsel.

MISCELLANEOUS

The agreements of the Authority with the owners of the 2014M1 Bonds are fully set forth in the Revenue Obligation Resolution. This Official Statement is not to be construed as a contract with the purchasers of the 2014M1 Bonds. Any statements herein involving matters of opinion or estimates, whether or not expressly so stated, are intended merely as such and not as representations of fact. This Official Statement has been approved by the Board of Directors of the Authority.

South Carolina Public Service Authority

/s/Jeffrey D. Armfield
Senior Vice President and
Chief Financial Officer

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Combined Statements of Net Position

South Carolina Public Service Authority
As of December 31, 2013 and 2012

	2013	2012
	(Thousands)	
ASSETS		
Current assets		
Unrestricted cash and cash equivalents	**$ 172,738**	$ 203,591
Unrestricted investments	**526,584**	335,053
Restricted cash and cash equivalents	**182,455**	273,542
Restricted investments	**762,650**	342,191
Receivables, net of allowance for doubtful accounts of $1,315		
and $1,333 at December 31, 2013 and 2012, respectively	**189,092**	205,034
Materials inventory	**113,865**	106,333
Fuel inventory		
Fossil fuels	**446,998**	483,407
Nuclear fuel-net	**163,147**	84,470
Interest receivable	**2,664**	1,731
Prepaid expenses and other current assets	**248,520**	252,886
Total current assets	**2,808,713**	2,288,238
Noncurrent assets		
Restricted cash and cash equivalents	**1,535**	1,911
Restricted investments	**109,060**	112,535
Capital assets		
Utility plant	**6,910,962**	6,744,928
Long lived assets-asset retirement cost	**507,394**	507,394
Accumulated depreciation	**(3,150,020)**	(2,954,471)
Total utility plant-net	**4,268,336**	4,297,851
Construction work in progress	**2,100,631**	1,643,507
Other physical property-net	**6,084**	6,560
Investment in associated companies	**6,840**	8,124
Unamortized debt expenses	**36,473**	32,951
Costs to be recovered from future revenue	**227,561**	220,165
Regulatory asset-asset retirement obligation	**603,663**	544,583
Other noncurrent and regulatory assets	**399,465**	433,144
Total noncurrent assets	**7,759,648**	7,301,331
Total assets	**$ 10,568,361**	$ 9,589,569
DEFERRED OUTFLOWS OF RESOURCES		
Accumulated decrease in fair value of hedging derivatives	**$ 19,367**	$ 34,891
Unamortized loss on refunded and defeased debt	**119,868**	138,072
Total deferred outflows of resources	**$ 139,235**	$ 172,963
Total assets & deferred outflows of resources	**$ 10,707,596**	$ 9,762,532

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, 2013 and 2012

	2013	2012
	(Thousands)	
LIABILITIES		
Current liabilities		
Current portion of long-term debt	$ 133,671	$ 334,842
Accrued interest on long-term debt	100,159	108,465
Commercial paper	372,073	329,283
Accounts payable	216,163	228,958
Other current liabilities	69,978	70,513
Total current liabilities	892,044	1,072,061
Noncurrent liabilities		
Construction liabilities	3,616	2,428
Asset retirement obligation liability	1,024,253	1,002,313
Total long-term debt (net of current portion)	6,313,821	5,222,951
Unamortized debt discounts and premiums	142,558	190,368
Long-term debt-net	6,456,379	5,413,319
Other credits and noncurrent liabilities	97,182	98,153
Total noncurrent liabilities	7,581,430	6,516,213
Total liabilities	$ 8,473,474	$ 7,588,274
DEFERRED INFLOWS OF RESOURCES		
Accumulated increase in fair value of hedging derivatives	$ 8,146	$ 3,423
Nuclear decommissioning costs	185,849	196,252
Total deferred inflows of resources	$ 193,995	$ 199,675
NET POSITION		
Net invested in capital assets	$ 893,339	$ 894,920
Restricted for debt service	92,662	140,038
Unrestricted	1,054,126	939,625
Total net position	$ 2,040,127	$ 1,974,583
Total liabilities, deferred inflows of resources & net position	$ 10,707,596	$ 9,762,532

Combined Statements of Revenues, Expenses and Changes in Net Position
South Carolina Public Service Authority
Years Ended December 31, 2013 and 2012

	2013	2012
	(Thousands)	
Operating revenues		
Sale of electricity	$ **1,796,230**	$ 1,868,365
Sale of water	**7,282**	6,594
Other operating revenue	**13,064**	12,838
Total operating revenues	**1,816,576**	1,887,797
Operating expenses		
Electric operating expenses		
Production	**104,740**	103,655
Fuel	**741,255**	829,085
Purchased and interchanged power	**217,311**	161,349
Transmission	**24,555**	24,080
Distribution	**10,727**	10,625
Customer accounts	**15,656**	15,660
Sales	**6,016**	5,803
Administrative and general	**91,792**	90,501
Electric maintenance expense	**106,463**	135,201
Water operation expense	**2,502**	2,217
Water maintenance expense	**890**	713
Total operation and maintenance expenses	**1,321,907**	1,378,889
Depreciation	**196,812**	187,382
Sums in lieu of taxes	**5,463**	5,209
Total operating expenses	**1,524,182**	1,571,480
Operating income	**292,394**	316,317
Nonoperating revenues (expenses)		
Interest and investment revenue	**3,945**	4,892
Net decrease in the fair value of investments	**(2,320)**	(2,966)
Interest expense on long-term debt	**(221,067)**	(215,414)
Interest expense on commercial paper and other	**(4,063)**	(3,135)
Amortization expense	**4,352**	(11,784)
Costs to be recovered from future revenue	**7,396**	9,155
U.S. Treasury subsidy on Build America Bonds	**7,486**	8,132
Other-net	**(2,185)**	(720)
Total nonoperating revenues (expenses)	**(206,456)**	(211,840)
Income before transfers	**85,938**	104,477
Capital contributions & transfers		
Distribution to the State	**(20,394)**	(19,617)
Reduction in water system equity	**0**	(8)
Total capital contributions & transfers	**(20,394)**	(19,625)
Change in net position	**65,544**	84,852
Total net position-beginning	**1,974,583**	1,889,731
Total net position-ending	$ **2,040,127**	$ 1,974,583

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, 2013 and 2012

		2013		2012
		(Thousands)		
Cash flows from operating activities				
Receipts from customers	$	**1,832,536**	$	1,891,420
Payments to non-fuel suppliers		**(262,973)**		(516,867)
Payments for fuel		**(736,022)**		(821,705)
Purchased power		**(217,386)**		(158,122)
Payments to employees		**(158,002)**		(159,670)
Other receipts-net		**272,613**		213,252
Net cash provided by operating activities		**730,766**		448,308
Cash flows from non-capital related financing activities				
Distribution to the State		**(20,394)**		(19,617)
Reduction in water system equity		**0**		(8)
Net cash used in non-capital related financing activities		**(20,394)**		(19,625)
Cash flows from capital-related financing activities				
Proceeds from sale of bonds		**1,866,374**		865,190
Proceeds from issuance of commercial paper notes		**284,897**		144,331
Repayment of commercial paper notes		**(242,107)**		(121,614)
Refunding / defeasance of long-term debt		**(856,621)**		(319,225)
Repayment of long-term debt		**(167,412)**		(151,210)
Interest paid on long-term debt		**(279,148)**		(265,682)
Interest paid on commercial paper and other		**(5,983)**		(5,000)
Construction and betterments of utility plant		**(730,119)**		(488,236)
Bond issuance and other related costs		**(34,217)**		50,120
Other - net		**(60,487)**		(23,048)
Net cash used in capital-related financing activities		**(224,823)**		(314,374)
Cash flows from investing activities				
Net (decrease)/increase in investments		**(610,834)**		35,440
Interest on investments		**2,969**		5,311
Net cash (used in)/provided by investing activities		**(607,865)**		40,751
Net (decrease)/increase in cash and cash equivalents		**(122,316)**		155,060
Cash and cash equivalents-beginning		**479,044**		323,984
Cash and cash equivalents-ending	$	**356,728**	$	479,044

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, 2013 and 2012

	2013	2012
	(Thousands)	
Reconciliation of operating income to net cash provided by operating activities		
Operating income	$ **292,394**	$ 316,317
Adjustments to reconcile operating income to net cash provided by operating activities		
Depreciation	**196,812**	187,382
Amortization of nuclear fuel	**28,500**	21,813
Net power gains involving associated companies	**(25,243)**	(44,686)
Distributions from associated companies	**22,444**	42,117
Advances to associated companies	**(4)**	(6)
Other income and expense	**12,895**	14,653
Changes in assets and liabilities		
Accounts receivable-net	**15,942**	3,576
Inventories	**28,877**	7,223
Prepaid expenses	**23,491**	3,844
Other deferred debits	**73,245**	1,550
Accounts payable	**58,992**	(71,911)
Other current liabilities	**319**	(17,011)
Other noncurrent liabilities	**2,102**	(16,553)
Net cash provided by operating activities	$ **730,766**	$ 448,308
Composition of cash and cash equivalents		
Current		
Unrestricted cash and cash equivalents	$ **172,738**	$ 203,591
Restricted cash and cash equivalents	**182,455**	273,542
Noncurrent		
Restricted cash and cash equivalents	**1,535**	1,911
Cash and cash equivalents at the end of the year	$ **356,728**	$ 479,044

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, 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 - 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.

D - 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.

E - 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.

F - 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.

G - 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 $83.7 million of interest in 2013. 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.

H - 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.

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

Years Ended December 31,	**2013**	2012
Annual Average Depreciation Percentages	**2.9%**	2.8%
Note: Depreciation expense includes amortization of property under capitalized leases.		

I - 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 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,	**2013**			2012		
	Nuclear	**Ash Ponds**	**Total**	Nuclear	Ash Ponds	Total
			(Millions)			
Reconciliation of ARO Liability:						
Balance as of January 1,	**$ 650.3**	**$ 352.0**	**$ 1,002.3**	$ 280.0	$ 67.4	$ 347.4
Accretion expense	**14.1**	**7.8**	**21.9**	12.1	3.6	15.7
Additional layer	**0.0**	**0.0**	**0.0**	358.2	281.0	639.2
Balance as of December 31,	**$ 664.4**	**$ 359.8**	**$ 1,024.2**	$ 650.3	$ 352.0	$ 1,002.3
Asset Retirement Cost (ARC):	**$ 334.3**	**$ 173.1**	**$ 507.4**	$ 334.3	$ 173.1	$ 507.4

J - 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, CTBR expense, materials and supplies.

2013 updates include a potential sale of Grainger Generating Station assets. The Authority is currently preparing the assets to comply with requirements in the pending sales contract. In addition, sales of coal (fuel stock pile) from the Jefferies Generating Station began in late 2013. Sale of coal will occur at both generation sites (Jefferies and Grainger) going forward into 2014.

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, asset retirement obligation (ARO) and various other balances in subsequent years.

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

Years Ended December 31,	2013	2012
Members	Ownership (%)	
City Utilities of Springfield (Missouri)	6.7	6.7
Cowlitz Public Utility District (Washington)	6.7	6.7
Gainesville Regional Utilities (Florida)	6.6	6.6
JEA (Florida)	20.0	20.0
MEAG Power (Georgia)	20.0	20.0
Nebraska Public Power District (Nebraska)	20.0	20.0
Santee Cooper (South Carolina)	20.0	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,	2013	2012
	(Thousands)	
TEA Investment:		
Balance as of January 1,	$ 7,932	$ 9,354
Reduction to power costs and increases in electric revenues	21,322	40,813
Less: Distributions from TEA	22,444	42,117
Less: Other (includes equity losses)	166	118
Balance as of December 31,	$ 6,644	$ 7,932
Due To/Due From TEA:		
Payable to	$ 29,249	$ 26,463
Receivable from	$ 1,592	$ 2,013

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, 2013, the trade guarantees are an amount not to exceed approximately $72.9 million.

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

Years Ended December 31,	**2013**	2012
Members	Ownership (%)	
Florida Municipal Power Agency (Florida)	**N/A**	N/A
Gainesville Regional Utilities (Florida)	**N/A**	N/A
JEA (Florida)	**25.0**	25.0
MEAG Power (Georgia)	**25.0**	25.0
Nebraska Public Power District (Nebraska)	**25.0**	25.0
Orlando Utilities Commission (Florida)	**N/A**	N/A
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, 2013 and 2012 was approximately $196,000 and $192,000, respectively. Since 2001, cumulative net direct cost and direct savings have been $4.1 million and $18.1 million, respectively.

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.

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. Neither financial statements nor an estimate of the Authority's share of start-up expenses were available as of December 31, 2013. 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.

L – 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,	**2013**	2012
	(Thousands)	
Deferred Outflows of Resources	**$ 139,235**	$ 172,963
Deferred Inflows of Resources	**193,995**	199,675

During 2013, the Authority continued to review GASB 63 requirements and found that certain items classified as Deferred Inflows of Resources at December 31, 2012 did not meet the criterion. The following table summarizes the change in classifications:

	2012
Combined Statements of Net Position	(Thousands)
Change:	
Current liabilities	
Other current liabilities	**$ 8,663**
Noncurrent liabilities	
Other credits and noncurrent liabilities	**45,961**
Total	**$ 54,624**
Combined Statements of Net Position	
Original:	
Deferred inflows of resources	
Compensated absences	**$ 8,663**
Unamortized gain on defeased debt	**1,168**
Unfunded pension and other post employment benefit costs	**44,793**
Total	**$ 54,624**

M - 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, a core business commodity input for the Authority, has historically been hedged in an effort to mitigate gas 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, 2013 and 2012 is below:

Cash Flow Hedges and Summary of Activity					
Years Ended December 31,			**2013**		2012
	Account Classification		(Millions)		
Fair Value					
Natural Gas	Regulatory Assets/Liabilities	**$**	**(11.5)**	$	(31.8)
Crude Oil	Regulatory Assets/Liabilities		**0.0**		0.0
Heating Oil	Regulatory Assets/Liabilities		**0.2**		0.3
Changes in Fair Value					
Natural Gas	Regulatory Assets/Liabilities	**$**	**20.3**	$	23.0
Crude Oil	Regulatory Assets/Liabilities		**0.0**		(1.6)
Heating Oil	Regulatory Assets/Liabilities		**(0.1)**		(1.2)
Recognized Net Gains (Losses)					
Natural Gas	Operating Expense-Fuel	**$**	**(21.2)**	$	(41.1)
Crude Oil	Operating Expense-Fuel		**0.0**		2.2
Heating Oil	Operating Expense-Fuel		**(0.2)**		(2.4)
Realized But Not Recognized Net Gains (Losses)					
Natural Gas	Regulatory Assets/Liabilities	**$**	**6.5**	$	(5.9)
Crude Oil	Regulatory Assets/Liabilities		**0.0**		0.0
Heating Oil	Regulatory Assets/Liabilities		**(0.2)**		0.1
Notional					
			MBTUs		
Natural Gas			**51,860**		33,610
			Gallons (000s)		
Heating Oil			**4,620**		6,468

N - 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 $14.4 million in 2013 and $13.4 million in 2012.

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.

O - 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 regards 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.

P - 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 2013 and 2012 totaled approximately $20.4 million and $19.6 million, respectively.

Q - New Accounting Standards -

STATEMENT NO. & ISSUE DATE	TITLE/SUMMARY	SUMMARY OF ACTION BY THE AUTHORITY
Statement No. GASB 61	**The Financial Reporting Entity: Omnibus-an amendment of GASB Statements No. 14 and No. 34**	
Issue Date: November 2010	Effective for Periods Beginning After: June 15, 2012	Reviewed and Adopted Early in 2012
Description:	This is a result of a reexamination of the previous reporting entity guidance contained in Statement No. 14. The most significant effect is the increased emphasis on a financial benefit or burden between the primary government and component units.	
Statement No. GASB 65	**Items Previously Reported as Assets and Liabilities**	
Issue Date: March 2012	Effective for Periods Beginning After: December 15, 2012	Reviewed and Adopted Early in 2012
Description:	This statement provides guidance and establishes accounting and financial reporting standards that reclassify, as deferred outflows of resources or deferred inflows of resources, certain items that were previously reported as assets and liabilities.	
Statement No. GASB 66	**Technical Corrections - 2012 - an amendment of GASB Statements No. 10 and No. 62**	
Issue Date: March 2012	Effective for Periods Beginning After: December 15, 2012	Reviewed and Adopted Early in 2012
Description:	This statement's objective is to improve accounting and financial reporting for a governmental financial reporting entity by resolving conflicting guidance that resulted from the issuance of two pronouncements, Statements No. 54, Fund Balance Reporting and Governmental Fund Type Definitions, and No. 62, Codification of Accounting and Financial Reporting Guidance Contained in Pre-November 30, 1989 FASB and AICPA Pronouncements.	
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	Under Review
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.	
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	Under Review
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.	
Statement No. GASB 69	**Government Combinations and Disposals of Government Operations**	
Issue Date: January 2013	Effective for Periods Beginning After: December 15, 2013	Under Review
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.	
Statement No. GASB 70	**Accounting and Financial Reporting for Nonexchange Financial Guarantees**	
Issue Date: April 2013	Effective for Periods Beginning After: June 15, 2013	Under Review
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.	
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.	Under Review
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.	

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,	**2013**	2012
	(Millions)	
CTBR Regulatory Asset:		
Balance	**$ 227.6**	$ 220.2
CTBR Expense/(Reduction to Expense):		
Net Expense	**$ (7.4)**	$ (9.2)

NOTE 3 – CAPITAL ASSETS:

Capital asset activity for the years ended December 31, 2013 and 2012 was as follows:

	Beginning Balances	**Increases**	**Decreases**	**Ending Balances**
	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**
	YEAR 2012			
	(Thousands)			
Utility plant	$ 6,724,937	$ 158,260	$ (138,269)	$ 6,744,928
Long lived assets-asset retirement cost	33,078	474,316	0	507,394
Accumulated depreciation	(2,902,820)	(189,796)	138,145	(2,954,471)
Total utility plant - net	3,855,195	442,780	(124)	4,297,851
Construction work in progress	1,230,771	1,046,049	(633,313)	1,643,507
Other physical property - net	6,783	0	(223)	6,560
Totals	$ 5,092,749	$ 1,488,829	$ (633,660)	$ 5,947,918

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-D – 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,	**2013**			2012 (1)		
Funds	**Cash & Cash Equivalents**	**Investments**	**Total**	Cash & Cash Equivalents	Investments	Total
			(Thousands)			
Current Unrestricted:						
Capital Improvement	**$ 40,798**	**$ 85,154**	**$ 125,952**	$ 29,032	$ 44,696	$ 73,728
Debt Reduction	**5,201**	**49,473**	**54,674**	1,656	51,677	53,333
Funds from Taxable Borrowings	**10,780**	**229,403**	**240,183**	70,155	84,016	154,171
General Improvement	**413**	**2,461**	**2,874**	1,412	1,450	2,862
Internal Nuclear Decommissioning Fund	**846**	**73,595**	**74,441**	4,262	76,691	80,953
Nuclear Fuel	**1,010**	**1,000**	**2,010**	8,015	3,051	11,066
Revenue and Operating	**89,103**	**31,999**	**121,102**	73,959	25,171	99,130
Special Reserve	**24,587**	**53,499**	**78,086**	15,100	48,301	63,401
Total	**$ 172,738**	**$ 526,584**	**$ 699,322**	$ 203,591	$ 335,053	$ 538,644
Current Restricted:						
Debt Service Funds	**$ 74,551**	**$ 118,270**	**$ 192,821**	$ 119,603	$ 128,900	$ 248,503
Funds from Tax-exempt Borrowings	**89,250**	**622,466**	**711,716**	118,598	196,505	315,103
Other	**18,654**	**21,914**	**40,568**	35,341	16,786	52,127
Total	**$ 182,455**	**$ 762,650**	**$ 945,105**	$ 273,542	$ 342,191	$ 615,733
Noncurrent Restricted:						
External Nuclear Decommissioning Trust	**$ 1,535**	**$ 109,060**	**$ 110,595**	$ 1,911	$ 112,535	$ 114,446
Total	**$ 1,535**	**$ 109,060**	**$ 110,595**	$ 1,911	$ 112,535	$ 114,446
TOTAL FUNDS	**$ 356,728**	**$ 1,398,294**	**$ 1,755,022**	$ 479,044	$ 789,779	$ 1,268,823
Cash and investments as of December 31, consisted of the following:						
Cash/Deposits			**$ 60,394**			$ 75,905
Investments			**1,694,628**			1,192,918
Total cash and investments			**$ 1,755,022**			$ 1,268,823

(1) The Authority's management determined a need for a change in the policy regarding the criteria for unrestricted and restricted cash and investments. This resulted in material changes to the classification of those funds as reported in 2012. Details of the revised fund criteria are defined below.

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 but represents amounts in excess above 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,	**2013**	2012
Total Portfolio	(Billions)	
Total Investments	**$ 1.7**	$ 1.2
Purchases	**55.0**	52.1
Sales	**54.5**	51.9
Nuclear Decommissioning Portfolios	(Millions)	
Total Investments	**$ 185.0**	$ 195.4
Purchases	**588.3**	624.0
Sales	**583.1**	618.9
Unrealized Holding Gains	**7.3**	26.8
Repurchase Agreements (1)	(Millions)	
Balance at December 31	**$ 238.6**	$ 348.1

(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, 2013 and 2012, 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, 2013 and 2012, 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, 2013 and 2012, the Authority had exposure to custodial credit risk for deposits as follows:

Depository Account Type		
	Bank Balance	
Years Ended December 31,	**2013**	2012
	(Thousands)	
Uninsured and collateral held by Bank's agent not in Authority's name	**$ 0**	$ 500

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, 2013 and 2012 were as follows:

Security Type / Issuer	Fair Value	
	2013	2012
Federal Agency Fixed Income Securities	(Thousands)	
Federal Home Loan Bank	**$ 465,448**	$ 475,406
Federal National Mortgage Association	**255,042**	98,068
Federal Farm Credit Bank	**215,631**	173,162
Federal Home Loan Mortgage Corp	**416,540**	22,911

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, 2013 and 2012:

	2013		2012	
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	**508,489**	**0.24**	199,858	0.01
Federal Agency Securities	**867,850**	**3.09**	594,291	3.56
Repurchase Agreements	**238,599**	**0.01**	348,139	0.01
U.S. Treasury Notes and Strips	**78,239**	**4.02**	49,180	7.67
Total	**$ 1,694,627**		$ 1,192,918	
Portfolio Weighted Average Maturity		**1.88**		1.94

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 $56.5 million par in U.S. Treasury Strips ranging in maturity from May 15, 2014 to May 15, 2039. The accounts also hold $57.0 million par in government agency zero coupon securities in the two portfolios ranging in maturity from November 15, 2014 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.

NOTE 5 – LONG-TERM DEBT:

Debt Outstanding

The Authority's long-term debt at December 31, 2013 and 2012 consisted of the following:

	2013	2012	Interest Rate(s) (1)	Call Price (2)
	(Thousands)		(%)	(%)
Capitalized Lease Obligations: (mature through 2014)	**$ 244**	$ 1,227	5.00	N/A
Revenue Obligations: (mature through 2053)				
1999 Taxable Series B	**1,700**	3,280	7.42	Non-callable
2002 Refunding Series A	**0**	12,190	N/A	N/A
2002 Refunding Series D	**0**	36,500	N/A	N/A
2003 Refunding Series A	**10,870**	255,880	4.75	100
2004 Tax-exempt Series A	**45,610**	55,720	5.00	100
2004 Taxable Series B	**6,365**	9,350	4.47-4.52	P&I Plus Make-Whole Premium
2004 Series M (4)	**30,031**	29,786	4.25-5.00	100/Accreted Value
2005 Refunding Series A	**125,295**	125,295	5.25-5.50	100
2005 Refunding Series B	**222,725**	232,080	5.00	100
2005 Refunding Series C	**78,150**	78,150	4.125-4.75	100
2005 Series M (4)	**12,701**	12,515	3.65-4.35	100/Accreted Value
2006 Tax-exempt Series A	**432,475**	442,475	3.625-5.00	100
2006 Taxable Series B	**59,500**	73,250	5.00-5.05	P&I Plus Make-Whole Premium
2006 Series M (4)	**7,811**	10,283	3.75-4.20	100/Accreted Value
2006 Refunding Series C	**114,755**	114,755	4.00-5.00	100
2007 Series A	**290,175**	303,005	4.00-5.00	100
2007 Refunding Series B	**82,855**	97,970	4.00-5.00	Non-callable
2008 Tax-exempt Series A	**391,985**	391,985	5.00-5.75	100
2008 Taxable Series B	**25,000**	260,000	6.808-8.368	P&I Plus Make-Whole Premium
2008 Series M (4)	**20,901**	25,083	3.00-4.80	100/Accreted Value
2009 Tax-exempt Refunding Series A	**84,605**	85,640	3.00-5.00	100
2009 Tax-exempt Series B	**160,075**	162,285	4.00-5.25	100
2009 Taxable Series C	**86,970**	87,040	4.12-6.224	P&I Plus Make-Whole Premium
2009 Tax-exempt Refunding Series D	**0**	10,500	N/A	N/A
2009 Tax-exempt Series E	**215,755**	250,965	3.00-5.00	100
2009 Taxable Series F	**100,000**	100,000	5.74	P&I Plus Make-Whole Premium
2010 Series M1(4)	**27,806**	28,400	1.35-4.30	100/Accreted Value
2010 Refunding Series B	**220,665**	231,060	3.00-5.00	100
2010 Series M2 (4)	**17,361**	17,233	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)	**26,655**	26,471	2.00-4.80	100/Accreted Value
2011 Taxable Series A (LIBOR Index Bonds)	**0**	316,632	N/A	N/A
2011 Refunding Series B	**282,700**	288,515	4.00-5.00	Non-callable
2011 Refunding Series C	**135,855**	135,855	4.375-5.00	100
2011 Series M2 (4)	**21,935**	21,923	1.40-4.20	100/Accreted Value
2012 Refunding Series A	**98,610**	98,610	3.00-5.00	100
2012 Refunding Series B	**25,200**	32,325	5.00	Non-callable
2012 Refunding Series C	**95,305**	119,145	5.00	Non-callable
2012 Tax-exempt Series D	**310,120**	312,160	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)	**21,124**	21,220	1.40-4.00	100/Accreted Value
2012 Series M2 (4)	**18,301**	18,205	1.10-3.70	100/Accreted Value
2013 Series M1 (4)	**23,366**	0	1.30-3.90	100/Accreted Value
2013 Tax-exempt Series A	**252,655**	0	5.00-5.75	100
2013 Tax-exempt Refunding Series B	**388,730**	0	5.00-5.125	100
2013 Taxable Series C	**250,000**	0	5.78	P&I Plus Make-Whole Premium
2013 Taxable Series D (LIBOR Index Bonds)	**450,000**	0	1 Month LIBOR plus 0.875-1.10	100
2013 Tax-exempt Series E	**506,765**	0	5.00-5.50	100
Total Revenue Obligations	**6,402,292**	5,556,566		
Other Long-Term Obligations: (mature through 2016)	**44,956**	0	N/A	N/A
Less: Current Portion - Long-term Debt	**133,671**	334,842		
Total Long-term Debt - (Net of current portion)	**$ 6,313,821**	$ 5,222,951		

(1) Interest Rates apply only to bonds outstanding as of December 31, 2013.
(2) Call Price may only apply to certain maturities outstanding at December 31, 2013.
(2) 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.
(3) 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, 2013 and 2012 was as follows:

	Gross LTD Beginning Balances	Increases	Decreases	Gross LTD Ending Balances	Current Portion LTD	Net LTD Ending Balances
YEAR 2013						
(Thousands)						
Capitalized Lease Obligations	**$ 1,227**	**$ 0**	**$ (983)**	**$ 244**	**$ 244**	**$ 0**
Other Long-Term Obligations	**0**	**44,956**	**0**	**44,956**	**0**	**44,956**
Revenue Obligations	**5,556,566**	**1,873,808**	**(1,028,082)**	**6,402,292**	**133,427**	**6,268,865**
Totals	**$ 5,557,793**	**$ 1,918,764**	**$ (1,029,065)**	**$ 6,447,492**	**$ 133,671**	**$ 6,313,821**
YEAR 2012						
(Thousands)						
Capitalized Lease Obligations	$ 2,469	$ 0	$ (1,242)	$ 1,227	$ 982	$ 245
Revenue Obligations	5,158,481	867,277	(469,192)	5,556,566	333,860	5,222,706
Totals	$ 5,160,950	$ 867,277	$ (470,434)	$ 5,557,793	$ 334,842	$ 5,222,951

Summary of Long-Term Principal and Interest

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

	PRINCIPAL				INTEREST			
Years Ending December 31,	**Capitalized Lease Obligations**	**Other Long-Term Obligations**	**Revenue Obligations**	**Total Principal**	**Capitalized Lease Obligations**	**Revenue Obligations (2)**	**Total Interest (2)**	**TOTAL**
	(Thousands)							
2014 (1)	$ 244	$ 0	$ 121,775	$ 122,019	$ 7	$ 312,201	$ 312,208	$ 434,227
2015 (1)	0	0	555,502	555,502	0	296,367	296,367	851,869
2016 (1)	0	44,956	333,878	378,834	0	283,381	283,381	662,215
2017	0	0	242,690	242,690	0	270,291	270,291	512,981
2018	0	0	191,822	191,822	0	260,770	260,770	452,592
2019-2023	0	0	974,581	974,581	0	1,155,976	1,155,976	2,130,557
2024-2028	0	0	670,884	670,884	0	972,057	972,057	1,642,941
2029-2033	0	0	757,025	757,025	0	802,882	802,882	1,559,907
2034-2038	0	0	848,755	848,755	0	590,684	590,684	1,439,439
2039-2043	0	0	838,615	838,615	0	380,331	380,331	1,218,946
2044-2048	0	0	492,600	492,600	0	194,209	194,209	686,809
2049-2053	0	0	374,165	374,165	0	51,177	51,177	425,342
Total	$ 244	$ 44,956	$ 6,402,292	$ 6,447,492	$ 7	$ 5,570,326	$ 5,570,333	$ 12,017,825

(1) Years 2014 - 2016 include projected interest for 2013 Taxable Series D (LIBOR Index Bonds).
(2) Does not reflect impact of subsidy interest payments on 2010 Series C (Build America Bonds).

Summary of Refunded and Defeased Bonds Outstanding and Unamortized Losses

Refunded and defeased bonds outstanding, original loss on refunding and the unamortized loss at December 31, 2013 are as follows:

Refunding Issue	Refunded Bonds			Refunded and Defeased Bonds Outstanding	Original Loss	Unamortized Loss
				(Thousands)		
Cash Defeasance	$	20,000	1982 Series A	$ 0	$ 2,763	$ 626
Commercial Paper	$	76,050	1973 Series			
		105,605	1977 Series			
		81,420	1978 Series	0	2,099	91
2003 Refunding Series A	$	336,385	1993 Refunding Series C			
		15,750	1995 Refunding Series A	0	57,064	886
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	8,496
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	29,932
2005 Refunding Series C	$	86,335	1993 Refunding Series C	0	12,125	6,433
2006 Refunding Series C	$	105,005	1999 Series A			
		10,000	2002 Series B	0	7,054	569
2007 Refunding Series B	$	105,370	1997 Refunding Series A	0	8,832	2,430
2009 Refunding Series A	$	99,515	1997 Refunding Series A			
		20,125	1998 Refunding Series B	0	8,707	6,194
2010 Refunding Series B	$	30,430	2001 Series A			
		118,600	2002 Series B			
		84,780	2002 Refunding Series D	0	22,954	13,854
2011 Refunding Series B	$	8,990	2002 Refunding Series D			
		291,825	2004 Series A	286,425	23,287	16,154
2011 Refunding Series C	$	134,715	2002 Series B			
		5,160	2007 Series A	0	4,362	3,954
2012 Refunding Series A	$	73,535	2003 Refunding Series A			
		34,160	2004 Series A	34,160	12,206	10,057
Feb 2012 Defeasance	$	5,615	2003 Refunding Series A	0	749	676
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	19,760	14,446	14,252
2013 Refunding Series C	$	35,584	2003 Refunding Series A			
		97,695	2008 Series B	0	4,601	4,524
2013 Taxable Series D (LIBOR Index)	$	54,700	2008 Series B			
		138,159	2011 Series A (LIBOR Index)			
		8,000	2012 Refunding Series C	0	920	740
Total				$ 340,345	$ 279,782	$ 119,868

Analysis of Prior Year Current Portion of Long-term

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 2012 current portion of long-term debt showing the amounts paid as debt service in 2013 and the amount refinanced. The remaining amount represents five percent of the original principal for all outstanding minibond issues.

Analysis of December 31, 2012 Current Portion of Long-term Debt:	(Thousands)
Principal debt service paid from 2013 Revenues	$ 166,393
Refinanced and other:	
2013 maturities refinanced	158,355
5% current portion requirement for original minibond issue amount (1)	10,094
Total	$ 334,842

(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 $158,024 current portion of long-term debt at December 31, 2011 showed that $149,502 was debt service paid from 2012 Revenues with the remaining $8,522 representing five percent of the original principal for outstanding minibond issues.

Reconciliations of Interest Charges

Years Ended December 31,	**2013**	2012
	(Thousands)	
Reconciliation of interest cost to interest expense:		
Total interest cost	**$ 278,274**	$ 264,140
Capitalized interest	**(32,751)**	0
Deferred interest expense	**(22,351)**	(46,732)
Interest charged to fuel expense	**(2,105)**	(1,994)
Total interest expense	**$ 221,067**	$ 215,414
Reconciliation of interest cost to interest payments:		
Total interest cost	**$ 278,274**	$ 264,140
Accrued interest - current year	**(100,159)**	(108,465)
Accrued interest - prior year	**108,465**	115,735
Interest released by refundings	**(5,030)**	(3,641)
Accretion on capital appreciation minibonds	**(2,402)**	(2,087)
Total interest payments	**$ 279,148**	$ 265,682

Debt Service Coverage

Years Ended December 31,	2013	2012
	(Thousands)	
Operating revenues	$ 1,816,576	$ 1,887,797
Other income	9,246	12,304
Total revenues and income	1,825,822	1,900,101
Operating expenses	(1,524,182)	(1,571,480)
Depreciation	196,812	187,382
Total expenses	(1,327,370)	(1,384,098)
Funds available for debt service prior to distribution to the State	498,452	516,003
Distribution to the State	(20,394)	(19,617)
Funds available for debt service after distribution to the State	$ 478,058	$ 496,386
Debt Service on Accrual Basis:		
Principal on long-term debt	$ 117,994	$ 142,765
Interest on long-term debt	221,067	215,414
Interest on long-term debt paid from borrowed proceeds	(12,720)	0
Long-term debt service paid from Revenues	326,341	358,179
Commercial paper and other principal and interest	6,670	5,914
Total debt service paid from Revenues	$ 333,011	$ 364,093
Debt Service Coverage Ratio:		
Excluding commercial paper and other:		
Prior to distribution to the State	1.52	1.44
After distribution to the State	1.46	1.38
Including commercial paper and other:		
Prior to distribution to the State	1.49	1.41
After distribution to the State	1.43	1.36

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 $7.0 billion and $6.6 billion at December 31, 2013 and 2012, respectively.

Bond market transactions for the year ended December 31, 2013 were as follows:

Revenue Obligations, 2013 Series M1	**Par Amount:**	**$23,254,800**	**Date Authorized:**	**May 1, 2013**
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 City of Bamberg and City of Georgetown				
- Interest rates range from 1.30 percent in 2018 and 3.90 percent in 2033				
Revenue Obligations, 2013 Tax-exempt Series A, Refunding Series B & Taxable Series C	**Par Amount:**	**$891,385,000**	**Date Authorized:**	**Aug 8, 2013**
Summary: - Issued on Aug 21, 2013 at an all-in true interest cost of 5.46 percent				
- Maturities between Dec 1, 2033 and Dec 1, 2043				
Revenue Obligations, 2013 Tax-exempt Series E	**Par Amount:**	**$506,765,000**	**Date Authorized:**	**Sep 26, 2013**
Summary: - Issued on Oct 4, 2013 at an all-in true interest cost of 5.34 percent				
- Maturities between Dec 1, 2048 and Dec 1, 2053				

As of December 31, 2013 and 2012, 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.

Bonds Outstanding Summary

As of December 31,	**2013**	2012
Outstanding Revenue Obligations	**$6.4 Billion**	$5.6 Billion
Estimated remaining interest payments	**$5.6 Billion**	$3.7 Billion
Issuance Years (inclusive)	**1999 through 2013**	1999 through 2012
Maturity Years (inclusive)	**2014 through 2053**	2013 through 2050

Note: Proceeds from these bonds were/will be used to fund a portion of the Authority's ongoing capital program or retire or refund certain outstanding debt of the Authority.

NOTE 6 – VARIABLE RATE DEBT:

The Board has authorized the issuance of variable rate debt not to exceed 20 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, 2013, 12 percent of the Authoirty'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.

On August 8, 2013, the Board authorized the sale of approximately $450.0 million in Revenue Obligations, 2013 Series D (LIBOR Index Bonds) (2013D Bonds). The 2013D Bonds were issued August 21, 2013 and will bear interest from their delivery date and will be payable on the first business day of each month. The 2013D Bonds will mature on June 1, 2015 and June 1, 2016. The interest rate is variable and is set monthly based on the London Interbank Offered Rate (LIBOR) plus 87.5 basis points, and 110.0 basis points, respectively.

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,	**2013**	2012
Commercial paper outstanding (000's)	**$ 372,073**	$ 329,283
Effective interest rate (at December 31)	**0.13%**	0.20%
Average annual amount outstanding (000's)	**$ 374,497**	$ 318,270
Average maturity	**45 Days**	50 Days
Average annual effective interest rate	**0.17%**	0.19%

At December 31, 2013 and 2012, 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 and $700.0 million, respectively. These agreements are used to support the Authority's issuance of commercial paper. There were no borrowings under the agreements during 2013 or 2012.

NOTE 7 – SUMMER NUCLEAR STATION:

Unit 1 - The Authority and South Carolina Electric and Gas (SCE&G) are parties to a joint ownership agreement providing that the Authority and SCE&G shall own Unit 1 at the V.C. 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 V. C. Summer Station - Unit 1		
Years Ended December 31,	**2013**	2012
	(Millions)	
Plant balances before depreciation	**$ 515.9**	$ 514.1
Accumulated depreciation	**326.7**	319.2
Operation & maintenance expense	**90.2**	81.6

Nuclear fuel costs are being amortized based on energy expended using the unit-of-production method. Costs include a component for estimated disposal expense of spent nuclear fuel. This amortization is 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 2015.

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 $185.0 million (adjusted to market) at December 31, 2013, 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.

Units 2 and 3 - The Authority and SCE&G are constructing and planning to operate two additional nuclear generating units (Summer Units 2 and 3) at V.C. Summer Nuclear Station 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 1,100 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 2013:

Month Completed	Unit(s)	Milestones
January	2 & 3	Energized Switchyard
March	2	Placed Nuclear Island Basemat (First Nuclear Concrete)
April	2	Set Module CR10 (Containment Vessel Bottom Head Support)
May	2	Set Containment Vessel Bottom Head
September	2	Set Structural Module CA04 (Reactor Vessel Cavity)
November	3	Placed Nuclear Island Basemat (First Nuclear Concrete)

The Authority anticipates that Unit 2 will go into service in early 2018, and Unit 3 will go into service approximately one year later.

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 is taking actions necessary to reduce its 45 percent ownership interest. 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 has remaining capital lease contracts with Central Electric Power Cooperative, Inc. (Central), covering transmission and various other facilities. The remaining lease term is for one year. Quarterly lease payments are based on a sum equal to the interest on and principal of Central's indebtedness to the Rural Utilities Service for funds borrowed to construct the above mentioned facilities. The Authority has options to purchase the leased properties at any time during the period of the lease agreements for an amount equal to Central's indebtedness remaining outstanding on the properties at the time the options are exercised or to return the properties at the termination of the lease. The Authority plans to exercise each and every option to acquire ownership of such facilities prior to expiration of the leases.

Total minimum lease payments on Central leases at December 31, 2013 are as follows:

Year Ending December 31,	(Thousands)
2014	$ 251
Less amounts representing interest	7
Principal payments	$ 244

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

Years Ended December 31,	**2013**	2012
	(Millions)	
Property under capital leases:		
Property balances	**$ 10.2**	$ 20.3
Accumulated depreciation	**8.7**	18.0
Operating lease payments (1)	**1.7**	3.0
(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 2014	
(2) The maximum amount due for coal car leases for 2013 and 2014 are $445,200 and $111,300, respectively.		
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 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 2013 and 2012 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 1,000 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 V. C. Summer Units 2 and 3.

NOTE 10 – COMMITMENTS AND CONTINGENCIES:

Budget – The Authority's 2014 three-year capital budget is as follows:

Years Ending December 31,	2014	2015	2016
		(Millions)	
V.C. Summer Units 2 and 3 (1)	$ 583.0	$ 528.6	$ 626.0
Environmental Compliance	39.1	48.9	30.7
General Improvements	207.8	198.8	189.9
Total Capital Budget (2)	$ 829.9	$ 776.3	$ 846.6

Budget Assumptions:
(1) Construction cash flows reflect 45 percent ownership through December 2014 and are subsequently reduced in accordance with the projected ownership sale date. Total estimated project cost including transmission is $3,961.5 million at a reduced ownership interest of 35 percent. At 45 percent, the total estimated project cost is $5,047.6 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, 2013. 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)			
2014	$	278,155	$	278,155
2015		198,054		198,054
2016		193,974		193,974
2017		98,902		98,902
2018		100,385		100,385
2019		76,418		76,418
Total	$	945,888	$	945,888

(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 purchased power contracts as of December 31, 2013:

Contracts with Minimum Fixed Payment Obligations

Number of Contracts	Delivery Beginning	Remaining Term	Obligations (Millions)
1	1985	21 Years	$ 54.6
1	2011	1 Year	9.9
1	2012	2 Years	46.4
1	2014	11 Years	0.0 (1)

(1) Contract obligation based on actual monthly purchase amount.

Contracts with Power Receipt and Payment Obligations (2)

Number of Contracts	Delivery Beginning	Remaining Term	Obligations (Millions)
1	2010	12 Years	$ 233.1
1	2013	20 Years	19.0
2	2013	30 Years	673.9
1	2013	20 Years	8.5
1	2014	28 Years	456.6

(2) 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 $8.4 million will be due in 2014, with remaining annual payments totaling $21.4 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. The CSX contract, effective beginning January 1, 2011, will continue to apply a price per ton of coal moved, along with a mileage based fuel surcharge and minimum tonnage obligation.

The Authority has commitments for nuclear fuel, nuclear fuel conversion, enrichment and fabrication contracts for V.C. Summer Units 1, 2 and 3. As of December 31, 2013, these contracts total approximately $490.4 million over the next 21 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-OEM 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 $47.2 million 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 transportation contract covering a maximum of 80,000 decatherms per day for 15 years.

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 2013. 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 2013, 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, 2013. In addition, there have been no third-party claims regarding environmental damages for 2013 or 2012.

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,	2013		2012	
	(Thousands)			
Unpaid claims and claim expense at beginning of year	$	1,778	$	1,612
Incurred claims and claim adjustment expenses:				
Add: Provision for current year events		2,940		2,392
Less: Payments for current and prior years		2,180		2,226
Total unpaid claims and claim expenses at end of year	$	2,538	$	1,778

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 V.C. 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), $500.0 million primary and $2.25 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 $3.8 million for the primary policy, $4.0 million for the excess policy and $1.4 million for the accidental outage policy.

SCE&G and the Authority maintain builder's risk insurance and marine cargo insurance for the V.C. Summer 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, 2013.

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 EPA has promulgated and is implementing the Clean Air Interstate Rule (CAIR) for SO2 and NOx emissions.

The Cross State Air Pollution Rule (CSAPR) was EPA's replacement for CAIR. However, the D.C. Circuit U.S. Court of Appeals overturned CSAPR on August 21, 2012, and instructed EPA to administer CAIR in the interim until EPA develops a replacement rule. CSAPR remains in the appeals process and is currently pending further review in the U.S. Supreme Court.

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.

The Authority has been operating under a settlement agreement, called the Consent Decree, which became effective June 24, 2004. The settlement with EPA and 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 capital costs to achieve emissions reductions over the period ending 2013. Capital costs have been 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. The Authority will continue to monitor both regulatory and legislative efforts to reduce greenhouse gas emissions to assess potential impacts to its operations.

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 was pre-released by EPA December 16, 2011, as the Mercury and Air Toxics (MATS) rule. It was published in the Federal Register on February 16, 2012, and became effective on April 16, 2012, with a compliance deadline for existing units of April 16, 2015.

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 July 20, 2012, EPA announced it is reconsidering certain technical aspects of the rule for new power plants. The Authority submitted comments to EPA by the January 7, 2013 deadline, and EPA completed the updated rule in March 2013. The compliance date for new power plants remained set for July 16, 2015. In June 2013, EPA reopened the public comment period on reconsideration of startup and shutdown provisions. The Authority submitted comments to EPA. EPA intends to complete this portion of reconsideration sometime in 2014. The compliance deadline for existing units remains April 16, 2015, with the potential for a state-approved one year extension.

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.

Further, EPA issued a proposed rule in June 2013 to amend the Steam Electric effluent guidelines 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.

The CWA, under Section 316(b), also 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 is expected to publish the final rule under the CWA Section 316(b) in April 2014. Based on the proposed rule and subsequent publications from the EPA, changes to the intake structures may be required at Cross and Winyah generating stations. Grainger generating station will not be subject to the final regulation, and the Authority continues to evaluate the remaining CWIS.

The EPA also 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.

DHEC promulgated a regulation effective June 2012 which requires permitting the withdrawal and use of surface water. Although existing withdrawers, including the Authority's generating and regional water systems are grandfathered into this regulation, the Authority was required to submit permit applications for these intakes. In 2013, the Authority received 30 year permits for all generating stations. These surface water withdrawal permits require the facility to develop drought contingency plans within 180 days after the permit is issued. Permits are pending for Lake Marion and Lake Moultrie regional water systems.

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 coal combustion residuals (CCRs) at the coal fired generating stations. The vast majority of the CCRs are fly ash, bottom ash, gypsum and scrubber sludge. The CCRs are either beneficially used or disposed of. The CCRs are exempt from hazardous waste regulation under the RCRA. However, EPA has proposed certain alternative revisions to the RCRA, that if adopted as a final rule, would add significant cost to the disposal and handling of CCRs and possibly restrict beneficial use. The EPA has entered into a Consent Decree which requires it to take final action regarding the proposed alternative revisions to the RCRA by December 19, 2014.

The Solid Waste Disposal Act and Energy Policy Act gives 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.

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 had recorded $15,000 for pollution remediation liabilities for each of the years ended December 31, 2013 and 2012. 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 – The Authority has paid approximately $221.6 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 U.S. Army Corps of Engineers’ (Corps) Cooper River Rediversion Project was completed in 1985. The Authority has also paid an additional $10.4 million in costs and attorney fees to the plaintiffs. The Authority submitted a claim seeking indemnification from the Corps on August 30, 2011. The Corps declined to pay the claim and the Authority appealed matter to the Armed Services Board of Contract Appeals (ASBCA). The ASBCA previously had determined that the contract between the Corps and the Authority required the Corps to indemnify the Authority for certain claims arising out of the construction and operation of the project. On February 14, 2013, the ASBCA ruled that the Authority is entitled to indemnification from the Corps in the amount of $234.9 million for costs incurred as a result of the Santee River Litigation. In addition, the ASBCA ruled that the Authority is entitled to interest on the costs pursuant to the Contract Disputes Act, calculated from August 20, 2001 until paid. The Corps has appealed this decision to the United States Court of Appeals for the Federal Circuit. Briefing on the appeal will be complete in the first quarter of 2014 and the Authority expects that the Court of Appeals will render a decision on the appeal in 2014.

In June 2012, several environmental advocacy groups filed suit against the Authority in the Court of Common Pleas in Horry County seeking injunctive relief with regard to closure of ash ponds at the Grainger Generating Station. The suit did not seek damages but alleged that an unlawful discharge of arsenic and other contaminants had occurred and requested that the court order the removal and offsite storage of all ash contained in the ponds. In April 2013, an environmental advocacy group filed suit against the Authority alleging that violations of the federal Clean Water Act had occurred at Grainger Generating Station. The suit did not seek damages but made claims for injunctive relief, civil penalties and costs and attorneys' fees. The Authority settled both suits in November 2013. The settlement did not require the Authority to make any payment to the litigants. The Authority intends to properly close the ash ponds by excavation and beneficial use of the ash in accordance with regulatory requirements.

In May 2013, Horry Cooperative, a member of Central, sued the Authority seeking indemnification for claims in a class action lawsuit brought against Horry Cooperative 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 Cooperative's complaint alleges the Authority knew the vapor barrier could cause moisture problems but failed to disclose the information to Horry Cooperative and failed to advise Horry Cooperative that the vapor barrier should be a recommendation rather than a requirement. The Authority does not yet know the number of customers or the amount of claims involved. The Authority intends to vigorously defend the lawsuit but cannot predict the outcome.

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 the SCRS was as follows:

Years Ended December 31,	**2013**	2012	2011
	(Millions)		
Payroll for Active Employees	**$ 126.9**	$ 125.7	$ 124.4

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 requirement" (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 will close 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 7.50 percent). The Authority contributed 10.45 percent of the total payroll for SCRS retirement. For 2013, 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,	**2013**	2012	2011
	(Millions)		
From the Authority	**$ 13.3**	$ 12.5	$ 11.7
From Employees	**9.2**	8.5	8.1
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 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, (7.50 percent employee cost and 10.45 percent employer cost); however, 5.00 percent of the employer amount is directed to the vendor chosen by the employee and the remaining 5.45 percent is to the Retirement System. As of December 31, 2013, the Authority had 36 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,	**2013**	2012
	(Millions)	
Total cost	**$ 1.1**	$ 1.2
Accrued liability	**5.3**	5.4

V.C. Summer Retirement - The Authority and SCE&G are parties to a joint ownership agreement at the V.C. 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, 2013 and 2012, the Authority had over-funded its share of requirements by $910,000 and $3.4 million, respectively. This receivable however, is offset by a regulatory liability as required by FASB ASC 715. The balances were approximately $15.0 million and $30.2 million for the unfunded portion of pension benefits at December 31, 2013 and 2012, 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, 2013.

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 734 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 of the employer (ARC), 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) for the current year was as follows:

Year Ended December 31,	**2013**	2012
	(Thousands)	
Annual required contribution	**$ 11,687**	$ 10,172
Interest on OPEB obligation	**513**	652
Adjustment to ARC	**(442)**	(563)
Annual OPEB cost	**11,758**	10,261
Net estimated employer contributions	**(11,302)**	(12,795)
Increase (decrease) in net OPEB obligation	**$ 456**	$ (2,534)
Net OPEB Obligation - beginning of year	**$ 9,325**	$ 11,859
Net OPEB Obligation - end of year	**$ 9,781**	$ 9,325

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, 2013 and the preceding two fiscal years were as follows:

Years Ended December 31,	**Annual OPEB Cost**	**Employer Amount Contributed**	**Net OPEB Obligation**	**Percentage Contributed**
	(Thousands)			(%)
2011	$ 9,841	$ 12,396	$ 11,859	126.0
2012	10,261	12,795	9,325	124.7
2013	**11,758**	**11,302**	**9,781**	**96.1**

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, 2013, the OPEB trust had assets of $32.9 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

V.C. Summer 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, 2013 and 2012 were approximately $10.1 million and $9.5 million, respectively.

In accordance with FASB ASC 715, the Authority had recorded a regulatory asset and liability of approximately $2.6 million and $5.3 million for the unfunded portion of OPEB costs at December 31, 2013 and 2012, 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, 2013.

NOTE 13 - CREDIT RISK AND MAJOR CUSTOMERS:

In 2013, the Authority had one customer that accounted for more than 10 percent of the Authority's sales:

Customer:	**2013**	2012
	(Millions)	
Central	**$ 1,038**	$ 1,115

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, 2013 and 2012 was $1.3 million.

NOTE 14 – SUBSEQUENT EVENT(S):

In conjunction with the preparation of these financial statements the Authority has evaluated subsequent events through February 21, 2014, the date the financial statements were available for issuance, and had the following to report:

- On January 27, 2014, the Authority's Board of Directors approved the sale of five percent of its ownership in V.C. Summer Units 2 and 3 to South Carolina Electric & Gas (SCE&G). Under the terms of the new agreement, SCE&G will own 60 percent of the new nuclear units and the Authority, 40 percent. Under the existing ownership agreement, SCE&G owns 55 percent and the Authority owns 45 percent. The five percent ownership interest would be acquired in three stages:
    (1) one percent at the commercial operation date of the first new nuclear unit, anticipated to be in the second quarter of 2018;
    (2) two percent no later than the first anniversary of such commercial operation date; and
    (3) two percent no later than the second anniversary date of such commercial operation date.

  The Agreement also provides that the Authority will not transfer any of its remaining ownership interest in the two new units until after the commercial operating date for both units.

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Appendix II

SUMMARY OF CERTAIN PROVISIONS OF THE REVENUE OBLIGATION RESOLUTION

The following statements are summaries of certain provisions of the Revenue Obligation Resolution. Except as otherwise provided in this Official Statement, terms used under this caption which are defined in the Revenue Obligation Resolution, including, but not limited to those defined hereinafter, are used herein as so defined. Certain other provisions of the Revenue Obligation Resolution are summarized under the caption "SECURITY FOR THE 2014M1 BONDS."

Definitions of Certain Terms Used in Revenue Obligation Resolution

The following words and phrases are defined in the Revenue Obligation Resolution as hereinafter set forth.

"Capital Costs" shall mean the Authority's costs of (i) physical construction of or acquisition of real or personal property or interests therein for any project, together with incidental costs (including legal, administrative, engineering, consulting and technical services, insurance and financing costs), working capital and reserves deemed necessary or desirable by the Authority (including but not limited to costs of supplies, fuel, fuel assemblies and components or interests therein), and other costs properly attributable thereto; (ii) all capital improvements or additions, including but not limited to, renewals or replacements of or repairs, additions, improvements, modifications or betterments to or for any project; (iii) the acquisition of any other property (tangible or intangible), capital improvements or additions, or interests therein, deemed necessary or desirable by the Authority for the conduct of its business; (iv) any other purpose for which bonds, notes or other obligations of the Authority may be issued under the Enabling Act or under other applicable State statutory provisions (whether or not also classifiable as an operating expense); and (v) the payment of principal, interest, and redemption, tender or purchase price of (a) any Obligations, Commercial Paper or other indebtedness issued by the Authority for the payment of any of the costs specified above, including capitalized interest on such indebtedness, or (b) any indebtedness issued by the Authority to refund any indebtedness described in the preceding clause (a).

"Government Obligations" shall mean direct obligations of, or obligations the principal of and interest on which are unconditionally guaranteed by, the United States of America.

"Investment Securities" shall mean any of the following which at the time are legal investments under the laws of the State of South Carolina for the moneys held hereunder then proposed to be invested therein: (1) Government Obligations; (2) certificates which evidence ownership of the rights to payment of the principal of or interest on Government Obligations; (3) bonds, debentures, notes or participation certificates issued by the Bank for Cooperatives, the Federal Intermediate Credit Bank, the Federal Home Loan Bank System, the Export-Import Bank of the United States, Federal Land Bank, the Federal National Mortgage Association, the Tennessee Valley Authority, or any other agency or corporation which is or may hereafter be created by or pursuant to an Act of Congress of the United States as an agency or instrumentality thereof; (4) obligations of state and local government municipal bond issuers, provision for the payment of the principal of and interest on which shall have been made by deposit with a trustee or escrow agent of non-callable obligations described in (1), (2), or (3) of this subparagraph, the maturing principal of and interest on which when due and payable, shall provide sufficient funds to pay the principal of and interest on such obligations of state and local government municipal bond issuers (5) Public Housing Bonds, or Project Notes, fully secured by contracts with the United States; (6) repurchase agreements with banks that are members of the federal reserve system or with government bond dealers recognized as primary dealers by the Federal Reserve Bank of New York that are secured by securities described in (1) and (3) above having a current market value at least equal to one hundred two per cent (102%) of the amount of the repurchase agreement; (7) obligations of the State of South Carolina, (8) obligations of other states and investment contracts which obligations or investment contracts are rated at the time of purchase by each rating agency then maintaining a rating on the Obligations at the request of the Authority (each, a "Rating Agency") in one of the three highest rating categories (as determined without regard to any refinement or graduation of such rating by a numerical modifier or otherwise, a "Rating Category") of such Rating Agency; (9) deposits in interest bearing deposits or certificates of deposit or similar arrangements issued by any bank or national banking association (including the Trustee), which deposits, to the extent not insured by the Federal

Deposit Insurance Corporation, shall be secured by obligations described in clauses (2), (3), (4) or (7) of this paragraph, having a current market value (exclusive of accrued interest) at least equal to one hundred five percent (105%) of the amount of such deposits, which obligations described in clauses (2), (3), (4) or (7) of this paragraph shall have been deposited in trust by such bank or national association with the trust department of the Trustee or with a federal reserve bank or branch or, with the written approval of the Authority and the Trustee, with another bank, trust company or national banking association for the benefit of the Authority and the appropriate fund or account as collateral security for such deposits; (10) corporate securities, including commercial paper and fixed income obligations, which are, at the time of purchase, rated by a Rating Agency in one of its three highest Rating Categories for comparable types of obligations; and (11) such other investments from time to time allowed under applicable law.

"Obligations" shall mean any obligations, issued in any form of debt, authorized by a supplemental resolution, including but not limited to bonds, notes, bond anticipation notes, and Qualified Swaps, which are delivered under the Revenue Obligation Resolution.

"Operation and Maintenance Expenses" shall mean the Authority's expenses of operating the System, including, but not limited to, all costs of purchased power, operation, maintenance, generation, production, transmission, distribution, repairs, replacements, engineering, transportation, administration and general, audit, legal, financial, pension, retirement, health, hospitalization, insurance, taxes and any other expenses actually paid or accrued, of the Authority applicable to the System, as recorded on its books pursuant to generally accepted accounting principles, subject to the limitations with respect to take or pay contracts as set forth under "Take or Pay Contracts." Operation and Maintenance Expenses shall not include (1) any costs or expenses for new construction, (2) charges for depreciation, (3) voluntary payments in lieu of taxes or (4) any taxes or tax payments now or hereafter required to be made to the State or any political subdivisions only out of surplus revenues, for example, payments required by Code Sections 58-31-90, 58-31-100 (2) and (3), and 58-31-110, Code of Laws of South Carolina 1976.

"Permitted Investments" shall mean the obligations referred to in (1), (2), (3) and (4) of the definition of the term "Investment Securities".

"Qualified Swap" shall mean, to the extent from time to time permitted by law, with respect to Obligations, any financial arrangement (i) which is entered into by the Authority with an entity that is a Qualified Swap Provider at the time the arrangement is entered into, (ii) which is a cap, floor or collar; forward rate; future rate; swap (such swap may be based on an amount equal either to the principal amount of such Obligations of the Authority as may be designated or a notional principal amount relating to all or a portion of the principal amount of such Obligations); asset, index, price or market-linked transaction or agreement; other exchange or rate protection transaction agreement; other similar transaction (however designated); or any combination thereof; or any option with respect thereto, executed by the Authority for the purpose of moderating interest rate fluctuations or otherwise, and (iii) which has been designated in writing to the Trustee by the Authority as a Qualified Swap with respect to such Obligations.

"Qualified Swap Provider" shall mean an entity whose senior long term obligations, other senior unsecured long term obligations or claims paying ability, or whose payment obligations under an interest rate exchange agreement are guaranteed by an entity whose senior long term debt obligations, other senior unsecured long term obligations or claims paying ability, are rated either (i) at least as high as the third highest Rating Category of each Rating Agency, but in no event lower than any Rating Category designated by each such Rating Agency for the Obligations subject to such Qualified Swap, or (ii) any such lower rating categories which each such Rating Agency indicates in writing to the Authority and the Trustee will not, by itself, result in a reduction or withdrawal of its rating on the Outstanding Obligations subject to such Qualified Swap that is in effect prior to entering into such Qualified Swap.

"Revenues" shall mean all the revenues, income, profits, tolls, rents, charges and returns of the Authority derived from its ownership or operation of the System, including the proceeds of any insurance covering business interruption loss relating to the System, but excluding other insurance proceeds and customer deposits.

System

The Authority's System, as defined in the Revenue Obligation Resolution, consists generally of (a) facilities for the purpose of acquiring, controlling, storing, preserving, treating, distributing and selling water for (i) navigation, power, irrigation, reclamation, or sale to residential, commercial, agricultural or industrial customers or other governmental entities; and (b) plants, works, structures, facilities and equipment for the generation, manufacture, transmission or distribution of water power and electric power and energy, and of any other forms of power and energy when authorized by the Enabling Act. The System shall not include separate projects established by the Authority for any corporate purpose of the Authority other than those projects and purposes described hereinabove, nor separate systems described under "Separate Systems."

Revenue Fund

The Revenue Obligation Resolution continues, for so long as any of the Revenue Obligations are Outstanding, the Revenue Fund. The Revenue Fund shall be held in trust and administered by the Authority. The Authority covenants and agrees in the Revenue Obligation Resolution to pay into the Revenue Fund, as promptly as practical after the receipt thereof, all Revenues.

Funds and Accounts

For the purpose of providing for the payment of the principal of, premium, if any, and interest on the Revenue Obligations, the Revenue Obligation Resolution creates a Revenue Obligation Fund. Payments into the Revenue Obligation Fund shall be made prior to the payments required to be made from, or retained in, the Revenue Fund to cover the cost of operation and maintenance of the System and the payments required to be made into the Lease Fund and the Capital Improvement Fund.

Order of Payments From Revenue Fund

Under the Revenue Obligation Resolution, moneys shall be disbursed by the Authority from the Revenue Fund in the following order:

1. *Revenue Obligation Fund*: To pay when due to the Trustee the Revenue Obligation Fund Payments.

2. *Operating and Maintenance*: To pay expense of operation and maintenance.

3. *Lease Fund*: To pay when due into the Lease Fund an amount equal to the next due lease payments.

4. *Capital Improvement Fund*: To pay during each Fiscal Year into the Capital Improvement Fund amounts at least equal to the Minimum Capital Improvement Requirement.

Any moneys remaining in the Revenue Fund each month after making the payments referenced above may be used by the Authority for any corporate purpose of the Authority.

Certain Moneys Not Required to be Deposited in Revenue Fund

The Revenue Obligation Resolution does not require the deposit into the Revenue Fund of any of the revenues, income, receipts, profits or other moneys of the Authority derived by the Authority through the ownership or operation of any separate system described under the section "Separate System" or through the ownership or operation of any separate project referred to under the section "System".

Authorization of Revenue Obligations

At any time one or more series of Revenue Obligations may be issued pursuant to the Revenue Obligation Resolution, upon the terms set forth in a Series Resolution, for any corporate purpose of the Authority, including the refunding or purchase of Revenue Obligations, provided there is no default under the Revenue Obligation Resolution.

Separate Systems

The System shall not include (i) any facilities for the purpose of providing water for sale to residential, commercial, agricultural or industrial customers or other governmental entities, or (ii) any facilities for the generation of any form of power and energy, or for the transmission and distribution of any form of power and energy, and any incidental properties constructed, acquired or leased in connection therewith, constructed or acquired by the Authority as a separate system, and if constructed or acquired with the proceeds of sale of bonds or other evidences of indebtedness, which bonds or other evidences of indebtedness are payable solely from the revenues or other income derived from the ownership or operation of such separate utility system, and may be further secured by a pledge of Revenues junior and subordinate to the pledge securing the Revenue Obligations and payable therefrom, but only after the revenues and other income derived from the ownership or operation of such separate utility system and pledged to the payment of such bonds or other indebtedness are so applied in accordance with the proceedings providing for the issuance of such bonds or other indebtedness.

Junior Lien Obligations

Nothing in the Revenue Obligation Resolution shall prevent the Authority from issuing bonds, notes, bond anticipation notes, warrants, certificates or other obligations or evidences of indebtedness the payment of which shall be made from the proceeds of Revenue Obligations or other indebtedness of the Authority or from Revenues, and if payable from Revenues shall be made junior and subordinate to the payment of the Revenue Obligations. The Authority may create special funds to provide for the payment of such obligations, payments to which shall be made after payments to the Revenue Obligation Fund, and may, if the Authority so provides, but need not be, junior to the payments into the Lease Fund.

Insurance

The Revenue Obligation Resolution requires the Authority to insure such of its various properties as are usually insured by utilities owning like properties in similar amounts and coverages, with insurance companies, and to carry liability insurance in reasonable amounts.

Sale, Lease or Other Disposition of Properties

Subject to the next sentence, the Authority may sell, lease, or otherwise dispose of any part of its properties on such terms and conditions as may be prescribed by its Board of Directors. The Authority shall not take any action described in the preceding sentence unless, in the judgment of the Authority's Board of Directors, such action is desirable in the conduct of the Authority's business and does not materially impair the Authority's ability to comply with the rate covenant provisions of the Revenue Obligation Resolution.

Take or Pay Contracts

The Revenue Obligation Resolution does not prohibit the Authority from entering into take or pay contracts, including take or pay contracts with a separate system described under section “Separate Systems,” to purchase power under conditions whereby payments the Authority is required to make may be calculated, in whole or in part, on the basis of power which the Authority does not purchase, require or obtain for whatever reasons. However, payments made by the Authority under such a take or pay contract for power not available for any reason other than an emergency or forced outage lasting not more than one year or normal and regularly scheduled maintenance outage may not be treated as Operation and Maintenance Expenses.

Capital Improvement Fund

The Revenue Obligation Resolution requires the deposit annually into the Capital Improvement Fund of an amount at least equal to the Minimum Capital Improvement Requirement defined as follows: an amount, which, together with the amounts deposited in the Capital Improvement Fund in the two immediately preceding Fiscal Years, will be at least equal to 8% of the revenues required by the Revenue Obligation Resolution to be paid into the Revenue Fund in the three immediately preceding Fiscal Years. Certain payments not made into the Capital Improvement Fund may be considered as a payment towards fulfillment of the Minimum Capital Improvement Requirement.

The moneys on deposit in the Capital Improvement Fund shall be used solely to pay Capital Costs.

Lease Fund

The Authority covenants that there will be paid monthly into the Lease Fund the amounts necessary to make payments under leases of properties or facilities leased to the Authority and used for the purpose of generating, transmitting and distributing all forms of power and energy.

Events of Default and Remedies Under the Revenue Obligation Resolution

A happening of one or more of the following constitutes an Event of Default under the Revenue Obligation Resolution:

(a) default in the due and punctual payment of any interest on any Revenue Obligation which shall continue for a period of 30 days; or

(b) default in the due and punctual payment of the principal of any Revenue Obligation, whether at the stated maturity thereof, at the mandatory redemption date, at the redemption date or upon declaration; or

(c) the Authority shall violate or fail to perform any of its covenants or agreements contained in the Revenue Obligation Resolution for 90 days after written notice of default is given to it by the Bond Fund Trustee or by the holder of any Revenue Obligation; or

(d) a default shall have occurred in respect of any bond, debenture, note or other evidence of indebtedness of the Authority, or in respect of any obligations of the Authority under any financing lease, whether now outstanding or existing or issued or otherwise undertaken hereafter, or under any indenture, resolution, lease or other agreement or instrument under which any such bond, debenture, note or other evidence of indebtedness or any such lease obligation has been or may be issued or by which any of the foregoing is or may be governed or evidenced, which default shall have resulted in the principal amount of such bond, debenture, note or other evidence of indebtedness or lease obligation becoming due and payable prior to its stated maturity or which default shall have been a default in the payment of principal when due and payable; or

(e) a decree or order by a court having jurisdiction in the premises shall have been entered judging the Authority as bankrupt or insolvent, or approving as properly filed a petition seeking reorganization or arrangement of the Authority under the Federal bankruptcy laws or any similar applicable Federal or South Carolina law, and such decree or order shall have continued undischarged or unstayed for a period of forty (40) days; or a decree or order of a court having jurisdiction in the premises for the appointment of a receiver or liquidator or trustee or assignee in bankruptcy or insolvency of the Authority or any of its property, or for the winding-up or liquidation of the Authority or any of its property, shall have been undischarged and unstayed for a period of sixty (60) days; or

(f) the Authority shall institute proceedings to be adjudicated a voluntary bankrupt, or shall consent to the filing of a bankruptcy proceeding against it, or shall file a petition or answer or consent seeking reorganization or arrangement under the Federal bankruptcy laws or any similar applicable Federal or South Carolina law, or shall consent to the filing of any such petition, or shall consent to the appointment of a receiver or liquidator or trustee or assignee in bankruptcy or insolvency of the Authority or of any of its property, or shall make an assignment for the benefit of creditors, or shall admit in writing its insolvency or inability to pay its debts generally as they become due, or any action shall be taken by the Authority in furtherance of any of the foregoing aforesaid purposes.

If an Event of Default has occurred, and shall not have been remedied, the Trustee or the holders of not less than 25% in principal amount of the Revenue Obligations then outstanding may declare the principal of all Revenue Obligations and the interest accrued thereon to be immediately due and payable, but such declaration may be rescinded under certain circumstances.

After the occurrence of an Event of Default and prior to the curing of such Event of Default, the Trustee may, to the extent permitted by law, take possession and control of the System and operate and maintain the same, prescribe rates for capacity or power sold or supplied through the facilities of the System, collect the gross revenues resulting from such operation and perform all of the agreements and covenants contained in any contract which the Authority is then obligated to perform. In such event, such gross revenues shall be applied, first to the payment of the reasonable expenses and liabilities of the Trustee and thereafter to the payment of operating expenses and principal of and interest on the Revenue Obligations. After all sums then due in respect of the Revenue Obligations have been paid, and after all Events of Default have been cured or secured, to the satisfaction of the Trustee, the Trustee is required to relinquish possession and control of the System to the Authority. At any such time the Trustee shall be entitled to the appointment of a receiver of the business and property of the System, of the moneys, securities and funds of the Authority pledged under the Revenue Obligation Resolution, and of the Revenues, and of the income therefrom, with all such powers as the court or courts making such appointment shall confer.

The Revenue Obligation Resolution empowers the Trustee to file proofs of claims for the benefit of the holders of the Revenue Obligations in bankruptcy, insolvency, or reorganization proceedings and to institute suit for the collection of sums due and unpaid in connection with the Revenue Obligations, to enforce specific performance of covenants contained in the Revenue Obligation Resolution or to obtain injunctive or other appropriate relief for the protection of the holders of the Revenue Obligations.

No holder of Revenue Obligations has any right to institute suit to enforce any provision of the Revenue Obligation Resolution or the execution of any trust thereunder (except to enforce the payment of principal or interest installments as they mature), unless the Trustee has been requested by the holders of not less than 25% in principal amount of the Revenue Obligations then outstanding to exercise the powers granted it by the Revenue Obligation Resolution or to institute such suit and unless the Trustee has refused or failed, within 60 days after the receipt of such request and after having been offered adequate security and indemnity, to comply with such request. In the event the Trustee has failed or refused to comply with the aforesaid request, the Revenue Obligation Resolution provides for the creation of an "Owners Committee."

Modifications of the Revenue Obligation Resolution

Modifications of the Revenue Obligation Resolution and of the rights and duties of the Authority and the holders of Revenue Obligations may be made with the consent of the Authority and written consent of the holders of not less than a majority of the Revenue Obligations at the time outstanding; provided that no modification shall be made which will (i) extend the fixed maturity date for the payment of any Revenue Obligation, or reduce the principal amount of or interest rate on any such Revenue Obligation or extend the time of payment of interest thereon or reduce any premium payable upon the prepayment or redemption thereof, or advance the date upon which any Revenue Obligation may first be called for redemption; or (ii) reduce the percentage of Revenue Obligations the holders of which are required to consent to any amendment to the Revenue Obligation Resolution; or (iii) give any Revenue Obligation or Revenue Obligations any preference over any other Revenue Obligation or Revenue Obligations or reduce the payments required to be made to the Revenue Obligation Fund, without the consent of the holders of all the Revenue Obligations affected thereby.

Defeasance

The obligations of the Authority under the Revenue Obligation Resolution shall be fully discharged and satisfied as to any Revenue Obligation and such Revenue Obligation shall no longer be deemed to be outstanding thereunder when payment of the principal of and the applicable redemption premium, if any, on such Revenue Obligation plus interest to the due date thereof (a) shall have been made or caused to be made in accordance with the terms thereof, or (b) shall have been provided by irrevocably depositing with the Trustee therefor in trust irrevocably appropriated and set aside exclusively for such payment (i) moneys sufficient to make such payments or (ii) Permitted Investments, maturing as to principal and interest in such amounts and at such times as will insure the availability of sufficient moneys to make such payment, and, except for the purposes of such payment, such Revenue Obligation shall no longer be secured by or entitled to the benefits of the Revenue Obligation Resolution; provided that, with respect to Revenue Obligations to be redeemed or otherwise prepaid prior to the stated maturities thereof, notice of such redemption or prepayment shall have been given or irrevocable provision shall have been made for the giving of such notice.

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[Date of Delivery]

Board of Directors
South Carolina Public Service Authority
One Riverwood Drive
Moncks Corner, South Carolina 29461

Re: $39,584,800 South Carolina Public Service Authority Revenue Obligations, 2014 Series M1

We have acted as bond counsel and have examined a certified copy of the Transcript of Proceedings and other proofs submitted to us, including the Constitution and Statutes of the State of South Carolina, in relation to the issuance by South Carolina Public Service Authority (the “Authority”) of the Authority's $39,584,800 Revenue Obligations, 2014 Series M1 (the “2014 M1 Bonds”) consisting of $32,393,000 Current Interest Bearing Bonds and $7,191,800 original principal amount of Capital Appreciation Bonds.

The 2014 M1 Bonds recite that they are issued for valid corporate purposes of the Authority under the authority of and in full compliance with the Constitution and Statutes of the State of South Carolina, including Title 58, Chapter 31, Code of Laws of South Carolina 1976, as amended, and proceedings of the Board of Directors of the Authority duly adopted, including a resolution adopted by the Board of Directors of the Authority on April 26, 1999 (as supplemented and amended from time to time, the “Revenue Obligation Resolution”). All capitalized terms used herein and not defined shall have the meaning ascribed to such terms in the Revenue Obligation Resolution.

As to questions of fact material to our opinion, we have relied upon representations of the Authority contained in the Revenue Obligation Resolution and in the certified Transcript of Proceedings and other certifications of public officials and others furnished to us, without undertaking to verify the same by independent investigation.

Based upon the foregoing, we are of the opinion, under existing statutes, regulations and court decisions, as follows:

1. The 2014 M1 Bonds have been authorized and issued in accordance with the Constitution and statutes of the State of South Carolina and constitute valid and legally binding special obligations of the Authority payable solely from and secured by a lien upon and pledge of the Revenue Fund and the revenues of the Authority's System and

other monies paid into the Revenue Fund (collectively, the "Revenues"), all as set forth and provided in the Revenue Obligation Resolution, on a parity with bonds heretofore and hereafter issued by the Authority pursuant to the Revenue Obligation Resolution on a parity with the 2014 M1 Bonds.

2. Interest on the 2014 M1 Bonds is excludable from gross income for federal income tax purposes and is not an item of tax preference for purposes of the federal alternative minimum tax imposed on individuals and corporations; it should be noted, however, that for the purpose of computing the alternative minimum tax imposed on certain corporations (as defined for federal income tax purposes), such interest is taken into account in determining adjusted current earnings. The opinion set forth in the preceding sentence is subject to the condition that the Authority comply with all requirements of the Internal Revenue Code of 1986, as amended, that must be satisfied subsequent to the issuance of the 2014 M1 Bonds in order that interest thereon be (or continue to be) excluded from gross income for federal income tax purposes. Failure to comply with certain of such requirements may cause interest on the 2014 M1 Bonds to be included in gross income for federal income tax purposes retroactive to the date of issuance of the 2014 M1 Bonds. We express no opinion regarding other federal tax consequences arising with respect to the 2014 M1 Bonds.

3. The 2014 M1 Bonds and the interest thereon are exempt from all state, county, school district, municipal, and all other taxes or assessments of the State of South Carolina, except inheritance, estate, transfer or certain franchise taxes.

We express no opinion regarding the accuracy, completeness, or sufficiency of any offering material relating to the 2014 M1 Bonds. Furthermore, we express no opinion regarding federal tax consequences arising with respect to the 2014 M1 Bonds, other than as expressly set forth herein.

It is to be understood that the rights of the owners of the 2014 M1 Bonds and the enforceability of the 2014 M1 Bonds may be limited by bankruptcy, insolvency, reorganization, moratorium and other similar laws affecting creditors' rights generally and by equitable principles, whether considered at law or in equity.

Very truly yours,