NEW ISSUE -- Book Entry

In the opinion of Bond Counsel, assuming continued compliance by the Authority with certain covenants, interest on the 2013M1 Bonds is excludable from gross income for federal income tax purposes under existing statutes, regulations and judicial decisions. Interest on the 2013M1 Bonds is not an item of tax preference in computing the alternative minimum taxable income of individuals or corporations. Interest on the 2013M1 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 2013M1 Bonds. The 2013M1 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.

$23,254,800
South Carolina Public Service Authority

santee cooper

Revenue Obligations, 2013 Series M1
Consisting of

$2,471,500 1.30% Current Interest Bearing Bonds Due January 1, 2018
$1,700,000 2.40% Current Interest Bearing Bonds Due January 1, 2023
$2,419,500 3.45% Current Interest Bearing Bonds Due January 1, 2028
$11,628,000 3.90% Current Interest Bearing Bonds Due January 1, 2033
$1,719,200 2.40% Capital Appreciation Bonds Due January 1, 2022
$1,055,600 3.45% Capital Appreciation Bonds Due January 1, 2027
$2,261,000 3.90% Capital Appreciation Bonds Due January 1, 2032

Dated: May 1, 2013

The Revenue Obligations, 2013 Series M1 (the "2013M1 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 2013M1 Bonds will be sold by the Authority directly to investors. The maximum amount of 2013M1 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 2013M1 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 2013M1 Bonds at the election of the Bondholders is limited to 5% of the original issue amount of the 2013M1 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, 2014 (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 2013M1 Bonds will be subject to redemption prior to maturity at the option of the Authority on and after January 1, 2014, as set forth herein.

The 2013M1 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 2013M1 Bonds are being issued to fund a portion of the cost of the Authority's ongoing capital improvement program.

The 2013M1 Bonds are not debts of the State of South Carolina (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 2013M1 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 16, 2013

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

No dealer, broker, salesman or other person has been authorized by the Authority or the Underwriters to give any information or to make any representations with respect to the 2013M1 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 2013M1 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 2013M1 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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INTRODUCTION

General

The purpose of this Official Statement is to set forth information concerning the South Carolina Public Service Authority (the "Authority"), Revenue Obligations, 2013 Series M1 (the "2013M1 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 documents 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. The Authority began electric power operations in 1942. The commercial operation of the regional water system began in October 1994.

Authorization of 2013M1 Bonds

The 2013M1 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 2013M1 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 2013M1 BONDS." By supplemental resolution duly adopted, the Authority authorized the issuance of the 2013M1 Bonds.

Indebtedness of the Authority

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 February 28, 2013 there was outstanding approximately $5,420,186,000 aggregate principal amount of Revenue Obligations.

In addition, the Authority has issued indebtedness evidenced by commercial paper notes (the "Commercial Paper Notes") and leases. As of February 28, 2013 there was outstanding $329,576,000 of Commercial Paper Notes and approximately $898,000 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. See "SECURITY FOR THE 2013M1 BONDS -- Lease Fund Payments" and "SECURITY FOR THE 2013M1 BONDS -- Commercial Paper Notes and Revolving Credit Agreement."

Purpose of the 2013M1 Bonds

The 2013M1 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, 2013 and will mature on January 1, 2018 at the interest rate of 1.30%, on January 1, 2023 at the interest rate of 2.40%, on January 1, 2028 at the interest rate of 3.45%, and on January 1, 2033 at the interest rate of 3.90%. 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, 2014 (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, 2014, 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, 2014 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 2013M1 Bonds tendered for purchase is limited to 5% of the original issue amount of the 2013M1 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, 2013 and will mature on January 1, 2022 at the interest rate of 2.40%, on January 1, 2027 at the interest rate of 3.45% and on January 1, 2032 at the interest rate of 3.90%. 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, 2014, 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, 2014, 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, 2014 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 2013M1 Bonds tendered for purchase is limited to 5% of the original issue amount of the 2013M1 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, 2022

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, 2022, 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, 2014	$ 203.21	Jul. 1, 2017	$ 220.91	Jan. 1, 2021	$ 240.14
Feb. 1, 2014	203.61	Aug. 1, 2017	221.35	Feb. 1, 2021	240.62
Mar. 1, 2014	204.02	Sep. 1, 2017	221.79	Mar. 1, 2021	241.10
Apr. 1, 2014	204.43	Oct. 1, 2017	222.23	Apr. 1, 2021	241.58
May 1, 2014	204.83	Nov. 1, 2017	222.67	May. 1, 2021	242.06
Jun. 1, 2014	205.24	Dec. 1, 2017	223.11	Jun. 1, 2021	242.54
Jul. 1, 2014	205.65	Jan. 1, 2018	223.56	Jul. 1, 2021	243.03
Aug. 1, 2014	206.06	Feb. 1, 2018	224.00	Aug. 1, 2021	243.51
Sep. 1, 2014	206.47	Mar. 1, 2018	224.45	Sep. 1, 2021	243.99
Oct. 1, 2014	206.88	Apr. 1, 2018	224.89	Oct. 1, 2021	244.48
Nov. 1, 2014	207.29	May 1, 2018	225.34	Nov. 1, 2021	244.97
Dec. 1, 2014	207.70	Jun. 1, 2018	225.79	Dec. 1, 2021	245.45
Jan. 1, 2015	208.12	Jul. 1, 2018	226.24	Jan. 1, 2021	245.94
Feb. 1, 2015	208.53	Aug. 1, 2018	226.69		
Mar. 1, 2015	208.95	Sep. 1, 2018	227.14		
Apr. 1, 2015	209.36	Oct. 1, 2018	227.59		
May 1, 2015	209.78	Nov. 1, 2018	228.05		
Jun. 1, 2015	210.19	Dec. 1, 2018	228.50		
Jul. 1, 2015	210.61	Jan. 1, 2019	228.95		
Aug. 1, 2015	211.03	Feb. 1, 2019	229.41		
Sep. 1, 2015	211.45	Mar. 1, 2019	229.87		
Oct. 1, 2015	211.87	Apr. 1, 2019	230.32		
Nov. 1, 2015	212.29	May 1, 2019	230.78		
Dec. 1, 2015	212.72	Jun. 1, 2019	231.24		
Jan. 1, 2016	213.14	Jul. 1, 2019	231.70		
Feb. 1, 2016	213.56	Aug. 1, 2019	232.16		
Mar. 1, 2016	213.99	Sep. 1, 2019	232.63		
Apr. 1, 2016	214.42	Oct. 1, 2019	233.09		
May 1, 2016	214.84	Nov. 1, 2019	233.55		
Jun. 1, 2016	215.27	Dec. 1, 2019	234.02		
Jul. 1, 2016	215.70	Jan. 1, 2020	234.48		
Aug. 1, 2016	216.13	Feb. 1, 2020	234.95		
Sep. 1, 2016	216.56	Mar. 1, 2020	235.42		
Oct. 1, 2016	216.99	Apr. 1, 2020	235.89		
Nov. 1, 2016	217.42	May 1, 2020	236.35		
Dec. 1, 2016	217.85	Jun. 1, 2020	236.82		
Jan. 1, 2017	218.29	Jul. 1, 2020	237.30		
Feb. 1, 2017	218.72	Aug. 1, 2020	237.77		
Mar. 1, 2017	219.16	Sep. 1, 2020	238.24		
Apr. 1, 2017	219.59	Oct. 1, 2020	238.72		
May 1, 2017	220.03	Nov. 1, 2020	239.19		
Jun. 1, 2017	220.47	Dec. 1, 2020	239.67		

Accreted Value Table for Capital Appreciation Bonds Maturity January 1, 2027

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, 2027, 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, 2014	$ 204.62	Jul. 1, 2017	$ 230.64	Jan. 1, 2021	$ 259.98
Feb. 1, 2014	205.20	Aug. 1, 2017	231.30	Feb. 1, 2021	260.72
Mar. 1, 2014	205.79	Sep. 1, 2017	231.96	Mar. 1, 2021	261.46
Apr. 1, 2014	206.38	Oct. 1, 2017	232.62	Apr. 1, 2021	262.21
May 1, 2014	206.97	Nov. 1, 2017	233.29	May 1, 2021	262.96
Jun. 1, 2014	207.56	Dec. 1, 2017	233.95	Jun. 1, 2021	263.71
Jul. 1, 2014	208.15	Jan. 1, 2018	234.62	Jul. 1, 2021	264.46
Aug. 1, 2014	208.74	Feb. 1, 2018	235.29	Aug. 1, 2021	265.22
Sep. 1, 2014	209.34	Mar. 1, 2018	235.96	Sep. 1, 2021	265.97
Oct. 1, 2014	209.94	Apr. 1, 2018	236.64	Oct. 1, 2021	266.73
Nov. 1, 2014	210.54	May 1, 2018	237.31	Nov. 1, 2021	267.49
Dec. 1, 2014	211.14	Jun. 1, 2018	237.99	Dec. 1, 2021	268.26
Jan. 1, 2015	211.74	Jul. 1, 2018	238.67	Jan. 1, 2022	269.02
Feb. 1, 2015	212.34	Aug. 1, 2018	239.35	Feb. 1, 2022	269.79
Mar. 1, 2015	212.95	Sep. 1, 2018	240.03	Mar. 1, 2022	270.56
Apr. 1, 2015	213.56	Oct. 1, 2018	240.72	Apr. 1, 2022	271.33
May 1, 2015	214.17	Nov. 1, 2018	241.41	May 1, 2022	272.11
Jun. 1, 2015	214.78	Dec. 1, 2018	242.10	Jun. 1, 2022	272.89
Jul. 1, 2015	215.39	Jan. 1, 2019	242.79	Jul. 1, 2022	273.66
Aug. 1, 2015	216.01	Feb. 1, 2019	243.48	Aug. 1, 2022	274.45
Sep. 1, 2015	216.62	Mar. 1, 2019	244.17	Sep. 1, 2022	275.23
Oct. 1, 2015	217.24	Apr. 1, 2019	244.87	Oct. 1, 2022	276.01
Nov. 1, 2015	217.86	May 1, 2019	245.57	Nov. 1, 2022	276.80
Dec. 1, 2015	218.48	Jun. 1, 2019	246.27	Dec. 1, 2022	277.59
Jan. 1, 2016	219.11	Jul. 1, 2019	246.97	Jan. 1, 2023	278.39
Feb. 1, 2016	219.73	Aug. 1, 2019	247.68	Feb. 1, 2023	279.18
Mar. 1, 2016	220.36	Sep. 1, 2019	248.39	Mar. 1, 2023	279.98
Apr. 1, 2016	220.99	Oct. 1, 2019	249.10	Apr. 1, 2023	280.78
May 1, 2016	221.62	Nov. 1, 2019	249.81	May 1, 2023	281.58
Jun. 1, 2016	222.25	Dec. 1, 2019	250.52	Jun. 1, 2023	282.38
Jul. 1, 2016	222.89	Jan. 1, 2020	251.23	Jul. 1, 2023	283.19
Aug. 1, 2016	223.52	Feb. 1, 2020	251.95	Aug. 1, 2023	284.00
Sep. 1, 2016	224.16	Mar. 1, 2020	252.67	Sep. 1, 2023	284.81
Oct. 1, 2016	224.80	Apr. 1, 2020	253.39	Oct. 1, 2023	285.62
Nov. 1, 2016	225.44	May 1, 2020	254.12	Nov. 1, 2023	286.43
Dec. 1, 2016	226.09	Jun. 1, 2020	254.84	Dec. 1, 2023	287.25
Jan. 1, 2017	226.73	Jul. 1, 2020	255.57	Jan. 1, 2024	288.07
Feb. 1, 2017	227.38	Aug. 1, 2020	256.30	Feb. 1, 2024	288.89
Mar. 1, 2017	228.03	Sep. 1, 2020	257.03	Mar. 1, 2024	289.72
Apr. 1, 2017	228.68	Oct. 1, 2020	257.76	Apr. 1, 2024	290.55
May 1, 2017	229.33	Nov. 1, 2020	258.50	May 1, 2024	291.38
Jun. 1, 2017	229.99	Dec. 1, 2020	259.24	Jun. 1, 2024	292.21

Date	Accreted Value	Date	Accreted Value	Date	Accreted Value
Jul. 1, 2024	$ 293.04	Oct. 1, 2025	$ 305.84	Jan. 1, 2027	$ 319.20
Aug. 1, 2024	293.88	Nov. 1, 2025	306.72		
Sep. 1, 2024	294.72	Dec. 1, 2025	307.59		
Oct. 1, 2024	295.56	Jan. 1, 2026	308.47		
Nov. 1, 2024	296.40	Feb. 1, 2026	309.35		
Dec. 1, 2024	297.25	Mar. 1, 2026	310.23		
Jan. 1, 2025	298.10	Apr. 1, 2026	311.12		
Feb. 1, 2025	298.95	May 1, 2026	312.01		
Mar. 1, 2025	299.80	Jun. 1, 2026	312.90		
Apr. 1, 2025	300.66	Jul. 1, 2026	313.79		
May 1, 2025	301.51	Aug. 1, 2026	314.69		
Jun. 1, 2025	302.38	Sep. 1, 2026	315.58		
Jul. 1, 2025	303.24	Oct. 1, 2026	316.49		
Aug. 1, 2025	304.10	Nov. 1, 2026	317.39		
Sep. 1, 2025	304.97	Dec. 1, 2026	318.30		

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Accreted Value Table for Capital Appreciation Bonds Maturity January 1, 2032

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, 2032, 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, 2014	$ 205.23	Jul. 1, 2017	$ 234.93	Jan. 1, 2021	$ 268.94
Feb. 1, 2014	205.89	Aug. 1, 2017	235.69	Feb. 1, 2021	269.81
Mar. 1, 2014	206.55	Sep. 1, 2017	236.45	Mar. 1, 2021	270.67
Apr. 1, 2014	207.22	Oct. 1, 2017	237.21	Apr. 1, 2021	271.55
May 1, 2014	207.88	Nov. 1, 2017	237.98	May 1, 2021	272.42
Jun. 1, 2014	208.55	Dec. 1, 2017	238.74	Jun. 1, 2021	273.30
Jul. 1, 2014	209.23	Jan. 1, 2018	239.51	Jul. 1, 2021	274.18
Aug. 1, 2014	209.90	Feb. 1, 2018	240.29	Aug. 1, 2021	275.07
Sep. 1, 2014	210.58	Mar. 1, 2018	241.06	Sep. 1, 2021	275.95
Oct. 1, 2014	211.26	Apr. 1, 2018	241.84	Oct. 1, 2021	276.84
Nov. 1, 2014	211.94	May 1, 2018	242.62	Nov. 1, 2021	277.74
Dec. 1, 2014	212.62	Jun. 1, 2018	243.40	Dec. 1, 2021	278.63
Jan. 1, 2015	213.31	Jul. 1, 2018	244.18	Jan. 1, 2022	279.53
Feb. 1, 2015	213.99	Aug. 1, 2018	244.97	Feb. 1, 2022	280.43
Mar. 1, 2015	214.68	Sep. 1, 2018	245.76	Mar. 1, 2022	281.33
Apr. 1, 2015	215.38	Oct. 1, 2018	246.55	Apr. 1, 2022	282.24
May 1, 2015	216.07	Nov. 1, 2018	247.35	May 1, 2022	283.15
Jun. 1, 2015	216.77	Dec. 1, 2018	248.14	Jun. 1, 2022	284.06
Jul. 1, 2015	217.47	Jan. 1, 2019	248.94	Jul. 1, 2022	284.98
Aug. 1, 2015	218.17	Feb. 1, 2019	249.75	Aug. 1, 2022	285.90
Sep. 1, 2015	218.87	Mar. 1, 2019	250.55	Sep. 1, 2022	286.82
Oct. 1, 2015	219.58	Apr. 1, 2019	251.36	Oct. 1, 2022	287.74
Nov. 1, 2015	220.28	May 1, 2019	252.17	Nov. 1, 2022	288.67
Dec. 1, 2015	220.99	Jun. 1, 2019	252.98	Dec. 1, 2022	289.60
Jan. 1, 2016	221.71	Jul. 1, 2019	253.80	Jan. 1, 2023	290.54
Feb. 1, 2016	222.42	Aug. 1, 2019	254.62	Feb. 1, 2023	291.47
Mar. 1, 2016	223.14	Sep. 1, 2019	255.44	Mar. 1, 2023	292.41
Apr. 1, 2016	223.86	Oct. 1, 2019	256.26	Apr. 1, 2023	293.36
May 1, 2016	224.58	Nov. 1, 2019	257.09	May 1, 2023	294.30
Jun. 1, 2016	225.30	Dec. 1, 2019	257.92	Jun. 1, 2023	295.25
Jul. 1, 2016	226.03	Jan. 1, 2020	258.75	Jul. 1, 2023	296.20
Aug. 1, 2016	226.76	Feb. 1, 2020	259.58	Aug. 1, 2023	297.16
Sep. 1, 2016	227.49	Mar. 1, 2020	260.42	Sep. 1, 2023	298.12
Oct. 1, 2016	228.22	Apr. 1, 2020	261.26	Oct. 1, 2023	299.08
Nov. 1, 2016	228.96	May 1, 2020	262.10	Nov. 1, 2023	300.04
Dec. 1, 2016	229.70	Jun. 1, 2020	262.95	Dec. 1, 2023	301.01
Jan. 1, 2017	230.44	Jul. 1, 2020	263.79	Jan. 1, 2024	301.98
Feb. 1, 2017	231.18	Aug. 1, 2020	264.64	Feb. 1, 2024	302.95
Mar. 1, 2017	231.93	Sep. 1, 2020	265.50	Mar. 1, 2024	303.93
Apr. 1, 2017	232.67	Oct. 1, 2020	266.35	Apr. 1, 2024	304.91
May 1, 2017	233.42	Nov. 1, 2020	267.21	May 1, 2024	305.89
Jun. 1, 2017	234.18	Dec. 1, 2020	268.07	Jun. 1, 2024	306.88

Date	Accreted Value	Date	Accreted Value	Date	Accreted Value
Jul. 1, 2024	$ 307.87	Jun. 1, 2027	$ 344.58	May 1, 2030	$ 385.67
Aug. 1, 2024	308.86	Jul. 1, 2027	345.69	Jun. 1, 2030	386.91
Sep. 1, 2024	309.86	Aug. 1, 2027	346.80	Jul. 1, 2030	388.16
Oct. 1, 2024	310.85	Sep. 1, 2027	347.92	Aug. 1, 2030	389.41
Nov. 1, 2024	311.86	Oct. 1, 2027	349.04	Sep. 1, 2030	390.67
Dec. 1, 2024	312.86	Nov. 1, 2027	350.17	Oct. 1, 2030	391.93
Jan. 1, 2025	313.87	Dec. 1, 2027	351.30	Nov. 1, 2030	393.19
Feb. 1, 2025	314.88	Jan. 1, 2028	352.43	Dec. 1, 2030	394.46
Mar. 1, 2025	315.90	Feb. 1, 2028	353.57	Jan. 1, 2031	395.73
Apr. 1, 2025	316.92	Mar. 1, 2028	354.71	Feb. 1, 2031	397.00
May 1, 2025	317.94	Apr. 1, 2028	355.85	Mar. 1, 2031	398.28
Jun. 1, 2025	318.96	May 1, 2028	357.00	Apr. 1, 2031	399.57
Jul. 1, 2025	319.99	Jun. 1, 2028	358.15	May 1, 2031	400.86
Aug. 1, 2025	321.02	Jul. 1, 2028	359.30	Jun. 1, 2031	402.15
Sep. 1, 2025	322.06	Aug. 1, 2028	360.46	Jul. 1, 2031	403.44
Oct. 1, 2025	323.10	Sep. 1, 2028	361.62	Aug. 1, 2031	404.75
Nov. 1, 2025	324.14	Oct. 1, 2028	362.79	Sep. 1, 2031	406.05
Dec. 1, 2025	325.18	Nov. 1, 2028	363.96	Oct. 1, 2031	407.36
Jan. 1, 2026	326.23	Dec. 1, 2028	365.13	Nov. 1, 2031	408.67
Feb. 1, 2026	327.28	Jan. 1, 2029	366.31	Dec. 1, 2031	409.99
Mar. 1, 2026	328.34	Feb. 1, 2029	367.49	Jan. 1, 2032	411.31
Apr. 1, 2026	329.40	Mar. 1, 2029	368.67		
May 1, 2026	330.46	Apr. 1, 2029	369.86		
Jun. 1, 2026	331.52	May 1, 2029	371.06		
Jul. 1, 2026	332.59	Jun. 1, 2029	372.25		
Aug. 1, 2026	333.66	Jul. 1, 2029	373.45		
Sep. 1, 2026	334.74	Aug. 1, 2029	374.66		
Oct. 1, 2026	335.82	Sep. 1, 2029	375.86		
Nov. 1, 2026	336.90	Oct. 1, 2029	377.08		
Dec. 1, 2026	337.99	Nov. 1, 2029	378.29		
Jan. 1, 2027	339.08	Dec. 1, 2029	379.51		
Feb. 1, 2027	340.17	Jan. 1, 2030	380.73		
Mar. 1, 2027	341.27	Feb. 1, 2030	381.96		
Apr. 1, 2027	342.37	Mar. 1, 2030	383.19		
May 1, 2027	343.47	Apr. 1, 2030	384.43		

DESCRIPTION OF BOOK-ENTRY ONLY SYSTEM

Unless and until the book-entry only system has been discontinued, the 2013M1 Bonds will be available only in book-entry form in authorized denominations. Owners of the 2013M1 Bonds will be listed in the books of record of the Registrar. Owners of the 2013M1 Bonds will not receive physical bond certificates representing their interests in the 2013M1 Bonds purchased.

Transfers of ownership interests in the 2013M1 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 2013M1 Bonds, unless the use of the book-entry system for the 2013M1 Bonds is discontinued.

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 2013M1 Bonds, and the total debt service in each calendar year indicated.

	Outstanding Revenue Obligations(2)	2013M1 Bonds	Total Debt
2013	$675,634(3)	$407	$676,040
2014	614,038(3)	610	614,648
2015	443,760	610	444,369
2016	457,777	610	458,387
2017	394,777	3,081	397,858
2018	416,964	578	417,542
2019	385,999	578	386,577
2020	378,720	578	379,298
2021	391,440	2,692	394,132
2022	297,475	2,278	299,753
2023	264,693	537	265,230
2024	267,393	537	267,930
2025	266,995	537	267,532
2026	261,360	2,222	263,582
2027	257,813	2,956	260,770
2028	269,997	453	270,451
2029	275,461	453	275,914
2030	254,651	453	255,105
2031	203,916	5,103	209,020
2032	165,953	12,081	178,034
2033	157,600		157,600
2034	159,590		159,590
2035	177,387		177,387
2036	177,994		177,994
2037	136,960		136,960
2038	95,729		95,729
2039	56,312		56,312
2040	77,981		77,981
2041	77,973		77,973
2042	74,703		74,703
2043	74,700		74,700
2044	75,102		75,102
2045	71,908		71,908
2046	69,391		69,391
2047	66,874		66,874
2048	64,356		64,356
2049	61,839		61,839

(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, 2012 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 percent 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 8.7% has been applied to the July 1, 2013 Subsidy Payment and the debt service on Revenue Obligations in calendar year 2013 has been adjusted accordingly.
(3) Includes actual interest on the $316,632,000 Revenue Obligations, 2011 Taxable Series A (LIBOR Index Bonds) through June 3, 2013, and thereafter based on a projected 1 Month LIBOR rate of 1.00%. Principal on the LIBOR Index Bonds shown in the year due rather than on an accrual basis.

SECURITY FOR THE 2013M1 BONDS

General

The 2013M1 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 2013M1 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 2012, distributions to the State and payments to local governments amounted to approximately $29,323,000.

There is no agency, other than the Authority, 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.”

Lease Fund Payments

As of February 28, 2013 the aggregate principal payments required to be made into the Lease Fund through the year 2014 was approximately $898,000 under existing leases of properties and facilities leased to the Authority.

The required payments into the Lease Fund are secured by a lien upon and pledge of Revenues junior to the lien and pledge securing Revenue Obligations.

Commercial Paper Notes and Revolving Credit Agreements

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. As of February 28, 2013, there was outstanding $329,576,000 aggregate principal amount of Commercial Paper Notes.

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”). 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.

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 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.

Present directors are listed below. The Governor has not appointed a director from the State's newly-created Seventh Congressional District, so there is one vacancy on the Board.

Name	Business	Residence	Term Expires May
O. L. Thompson, Chairman	Business Executive	Charleston	2011(1)
William A. Finn, First Vice Chairman(2)	Business Executive	Charleston	2013
Barry D. Wynn Second Vice Chairman	Business Executive	Spartanburg	2014
David A. Springs	Retired Business Executive	Murrells Inlet	2008(1)
Kristofer Clark	Business Executive	Easley	2012(1)
Cecil E. Viverette	Retired Business Executive	Hilton Head	2012(1)
J. Calhoun Land, IV	Attorney	Manning	2013
Peggy H. Pinnell	Business Executive	Moncks Corner	2014
W. Leighton Lord, III(2)	Attorney	Columbia	2015
James R. Sanders, Jr.	Business Executive	Gaffney	2016
David F. Singleton	Business Executive	Myrtle Beach	2016

(1) Although their terms expired as indicated, they may continue to serve until successors have been appointed and qualified.
(2) On April 30, 2013, the Governor of South Carolina appointed W. Leighton Lord, III as Chairman of the Board. The Governor also reappointed William A. Finn to the 1st Congressional District seat. These appointments become effective upon the appointee being found qualified by the PURC and being confirmed by the Senate. The Directors may continue to serve in their current position in the interim.

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	30 years
Elaine G. Peterson	Executive Vice President and Chief Financial Officer	35 years
James E. Brogdon, Jr.	Executive Vice President and General Counsel	8 years
Rennie M. Singletary, III	Executive Vice President, Corporate Services	35 years
Terry L. Blackwell	Senior Vice President, Power Delivery	35 years
L. Phil Pierce	Senior Vice President, Generation	34 years
Marc R. Tye	Senior Vice President, Customer Service	30 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.

Elaine G. Peterson joined the Authority in 1977 as an accountant in the Authority's Career Foundation Program. Since that time she has held various positions, including Assistant to the Controller, Program for Employee Participation Coordinator, and Controller. She received a Bachelor of Science degree in Accounting from Clemson University and a Masters in Business Administration from The Citadel. Elaine Peterson will retire June 30, 2013. Effective July 1, 2013, Jeffrey D. Armfield will become Senior Vice President and Chief Financial Officer.

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.

Rennie M. Singletary joined the Authority in 1977 as an engineer. Since that time he has held various positions, including Jefferies Generating Station Manager and Vice President of Fossil and Hydro Generation. He received a Bachelor of Science degree and a Master of Science degree in Mechanical Engineering from Clemson University and a Masters in Business Administration from The Citadel.

Terry L. Blackwell joined the Authority in 1977 as an engineer in the Authority's Career Foundation Program. Since that time he has held various positions, including Manager of Transmission Operations and Supervisor of Power Supply Planning. He received a Bachelor of Science degree in Electrical Engineering from N.C. State University. Terry Blackwell will retire June 30, 2013. Effective July 1, 2013, Ben Fleming Jr. will become Senior Vice President of Power Delivery.

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.

The Authority had 1,780 employees as of February 28, 2013. 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. The Authority is one of the nation's largest municipal wholesale utilities, whose System serves directly or indirectly approximately 2 million customers 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.

The Authority's direct customers currently include 29 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, approximately 744,000 customers are served indirectly by the Authority. See "CUSTOMER BASE -- Wholesale."

The Authority also serves directly approximately 167,000 residential, commercial and small industrial retail customers in parts of Berkeley, Georgetown and Horry counties. See "CUSTOMER BASE -- Direct Retail Service Area."

The Authority, from time to time, negotiates with existing and prospective customers and entities for the sale of electric power under long-term contracts. The Authority is unable to predict the outcome of such negotiations.

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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, 2012, which is the latest information provided to the Authority.

Central Cooperatives	Headquarters	Customers
Aiken Electric Cooperative, Inc.	Aiken	45,712
Berkeley Electric Cooperative, Inc.	Moncks Corner	85,645
Black River Electric Cooperative, Inc.	Sumter	31,481
Blue Ridge Electric Cooperative, Inc	Pickens	63,582
Broad River Electric Cooperative, Inc	Gaffney	20,450
Coastal Electric Cooperative, Inc.	Walterboro	11,502
Edisto Electric Cooperative, Inc.	Bamberg	19,907
Fairfield Electric Cooperative, Inc.	Winnsboro	26,151
Horry Electric Cooperative, Inc.	Conway	67,993
Laurens Electric Cooperative, Inc	Laurens	53,164
Little River Electric Cooperative, Inc	Abbeville	14,056
Lynches River Electric Cooperative, Inc.	Pageland	20,450
Marlboro Electric Cooperative, Inc.	Bennettsville	6,535
Mid-Carolina Electric Cooperative, Inc.	Lexington	52,193
Newberry Electric Cooperative, Inc.	Newberry	12,681
Palmetto Electric Cooperative, Inc.	Ridgeland	68,305
Pee Dee Electric Cooperative, Inc.	Darlington	30,209
Santee Electric Cooperative, Inc.	Kingstree	44,033
Tri-County Electric Cooperative, Inc.	St. Matthews	17,890
York Electric Cooperative, Inc	York	44,997

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"), small amounts purchased from others and amounts provided by Broad River Electric Cooperative's ownership interest in a small run of the river hydroelectric plant. The amounts supplied by the Authority are determined under the terms of an agreement between the Authority and Central (the "Central Agreement") which became effective January 1981 upon approval by the Rural Electrification Administration, currently the Rural Utilities Services (the "RUS"). In 2012, revenues pursuant to the Central Agreement amounted to approximately 59.6% of revenues from sales.

The Authority and Central adopted an amendment to the Central Agreement in January 1988 which was approved by the RUS on July 20, 1988 and which revised the cost of service methodology, lowered the cost responsibility and rates to Central and extended the contract for a 35 year period ending on March 31, 2023. In addition to the change in the costing methodology, the amendment relinquishes all ownership rights of future generation by Central.

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 and are connected to the transmission system of Duke Energy Carolinas, LLC ("Duke Carolinas"), a subsidiary of Duke Energy Corporation ("Duke"): 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, which is approximately 22% of Central's current energy requirements, will transition to the new supplier over a six-year period beginning in 2013, and by 2019 will amount to approximately 1,000 Megawatts ("MW"). The September 2009 agreement also provides that neither party will exercise any right to terminate the Central Agreement effective on or before December 31, 2030 and that the parties agree to negotiate in good faith terms and conditions by which the rights of the Authority and Central to terminate the Central Agreement will be deferred beyond 2030. On February 25, 2013, the Authority's Board of Directors gave preliminary approval to an amendment to the Central

Agreement with authorization for management to proceed with finalizing the amendment. Under the proposed amendment, the Central Agreement would not terminate before 2059.

Under State law, the Authority may only serve directly new industrial customers located in its direct service area. However, if any industrial customers located outside the Authority's service area discontinue accepting electrical service from the Authority, the Authority may sell electrical service to new customers from its major transmission lines in areas outside the Authority's service area in an amount not exceeding that which was lost by such discontinuation of service.

If a new industrial customer is served by a Central Cooperative, the Authority will provide such power to the customer through the Central Cooperative (except for new industrial customers served by one of the former Saluda cooperatives after the end of the transition period described above). 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.

For additional information on Central and the Central Cooperatives, please refer to the 2009 Statistical Report, Rural Electric Borrowers (RUS Informational Publication 201-1) which is the latest available statistical report, copies of which may be obtained from the U.S. Government Printing Office, Superintendent of Documents, Mail Stop: SSOP, Washington, D.C. 20402-0001.

Other Wholesale. In addition to Central, the Authority provides wholesale electric service to the City of Georgetown, the City of Bamberg, and South Carolina Electric & Gas ("SCE&G") pursuant to long-term contracts. The initial terms of the contracts with the City of Bamberg and the City of Georgetown recently expired. Both contracts remain in effect unless and until terminated by 24 months advance written notice of such intention from either party to the other. The City of Georgetown has given notice of termination in 2014 as part of a process to solicit proposals for future service and has invited the Authority to participate in this process. The City of Bamberg is served under a 10 year term that expired in 2011 and has requested the Authority's proposed terms for a 10 year extension for consideration. The Authority desires to negotiate new long-term contracts with both cities but cannot predict the outcome of these negotiations. Sales to these customers and off-system sales to other utilities and power marketers during 2012 represented approximately 1.6% of revenues from sales.

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

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

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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 2,782 miles of distribution lines. The table on the following page presents retail customer growth from 2008 through 2012 in these areas.

Retail Customers

Year	Residential	Commercial and Small Industrial	Total	Annual Increase %
2008	131,869	30,788	162,657	0.8
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

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 a fuel adjustment clause and demand sales adjustment clause. Sales to this customer group represented approximately 17.9% of revenues from sales in 2012.

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 fuel adjustment clauses, demand sales adjustment clauses, minimum demand charges and other provisions generally used in large industrial power rate schedules. The average cost per kilowatthour ("kWh") varies depending upon the customer's usage and load factor.

Sales to large industrial customers during 2012 represented approximately 20.9% of revenues from sales, which includes 8.6% for Alumax of South Carolina, Inc. ("Alumax"), 5.1% 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.

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, 2013 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 on or after December 1, 2013 if certain conditions are met.

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. The contract currently provides for delivery of approximately 300 MW of power, none of which is provided under the supplemental curtailable rate schedule.

POWER SUPPLY AND POWER MARKETING

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	128	128	Hydro
Wilson Dam Generating Station	Lake Marion	1950	2	2	Hydro
Jefferies Generating Station	Moncks Corner				
Nos. 1 and 2		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 Station(3)	Jenkinsville	1983	318(4)	318(4)	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	4	4	LMG(5)
Lee County Landfill Gas Station	Bishopville	2005	10	10	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			5,425	5,183	

(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) Virgil C. Summer Nuclear Station ("Summer Nuclear Station").
(4) Represents the Authority's one-third ownership interest.
(5) Landfill Methane Gas ("LMG").

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 13% summer reserve margin. The Authority's current total summer MCR of its owned generating capacity is 5,183 MW, of which 3,480 MW is generated by coal-fueled units, 130 MW by hydroelectric stations, 318 MW by a nuclear-fueled unit, 1,226 MW by oil, gas or oil/gas-fueled units and 29 MW from landfill methane gas. 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 38 MW of biomass capacity and associated energy under a power purchase agreement that commenced in September 2010 and extends for fifteen years. 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 2015. The electric generation, transmission and distribution facilities owned by the Authority as well as certain generation and 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	130	2.1
Landfill Methane Gas	29	0.5
Total MCR	5,183	
Purchases	904	14.9
Total MCR and Purchases	6,087	100.00

Non-Nuclear Generating Availability. The following table sets forth performance indicators for the Authority's coal-fired generation for the years 2010 through 2012.

	2010	2011	2012
Capacity Factor - %	62.6	57.9	45.7
Availability Factor - %	91.9	88.7	94.5
Forced Outage Rate - %	2.6	5.9	2.3
Net Heat Rate (BTU/Kwh)	10,034	9,987	9,854

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 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."

On October 19, 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. 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 those units. 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 EPA and The 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.

Summer Nuclear Station. The Authority owns a one-third undivided interest in the Summer Nuclear Station located in Fairfield County, South Carolina. The station 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 the station on its own behalf and as the Authority's agent.

The following table sets forth certain performance indicators for the Summer Nuclear Station for the years 2010 through 2012 and for the period of commercial operation, January 1, 1984 through December 31, 2012. The next refueling outage is scheduled to commence on April 4, 2014.

	2010	2011	2012	January 1, 1984- December 31, 2012
Net Generation -- MWh	8,487,079	7,426,233	7,281,603	195,961,024
Capacity Factor -- %	100.3	87.8	85.8	83.1
Availability Factor -- %	99.1	87.1	84.9	84.9
Forced Outage Rate -- %	0.9	0.7	0.0	2.5

The Nuclear Regulatory Commission (the "NRC") oversees plant performance through the Plant Performance Review (the "PPR"). The PPR is an ongoing process that combines the evaluation of inspection results and safety performance information. PPR results are classified into the areas of Reactor Safety, Radiation Safety and Safeguards and are used to identify and evaluate trends. Results are classified as green, yellow, white or red, with green being most favorable. A green classification indicates that plant management has proper oversight and does not require additional regulator oversight. Through the fourth quarter of 2012, all PPR classifications for Summer Nuclear Station are coded green. The station is in the Licensee Response column of the NRC Action Matrix.

In 2004, the NRC extended the operating license for Summer Nuclear Station to August 6, 2042, which was an additional twenty 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 1,261 miles of 230 kilovolt ("kV"), 1,814 miles of 115 kV, 1,733 miles of 69 kV, 14 miles of 46 kV and 97 miles of 34 kV and below overhead and underground transmission lines. The Authority operates 104 transmission substations and switching stations serving 84 distribution substations and 474 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 Progress Energy Carolinas ("Progress Energy") at eight locations; with Southern Company Services, Inc. ("Southern Company") at one location; and with Duke Carolinas, at two locations. The Authority is also interconnected with SCE&G, Duke, 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, Progress Energy, Duke, 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 2012, 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
Coal	57.4
Natural Gas and Oil	17.0
Nuclear	8.8
Owned Hydro Generation	0.9
Purchases	15.5
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

1,714 coal cars and periodically supplements its fleet with cars provided by the railroad and through short term leases. Currently, the Authority has 106 cars on short term lease.

The Authority uses a methodology that reflects the impact of substantial 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 226 days of coal on hand as of February 28, 2013. In terms of tonnage, as of February 28, 2013 the Authority had approximately 4.5 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 ("Transco") 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 has determined that all transactions executed under the policy will be executed through TEA.

Nuclear. Under the Joint Ownership Agreement for Summer Nuclear Station, Unit 1, SCE&G acts for itself and as agent for the Authority in the operation of the Summer Nuclear Station 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.

Summer Nuclear Station has licensed on-site spent fuel storage capability until 2017 while still maintaining full core discharge capability. SCE&G has signed contracts with HOLTEC International, Chicago Bridge & Iron and Westinghouse Electric Company, Inc. ("Westinghouse") to build a licensed Independent Spent Fuel Storage Installation ("ISFSI") to commence receiving spent fuel in 2015.

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 Department of Energy (the "DOE") for spent fuel and high level waste disposal services for the operating life of the Summer Nuclear Station. The Nuclear Waste Policy Act and the Standard Contract require 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 Station or any other utility, and has not indicated when it anticipates doing so.

On January 28, 2004, SCE&G and the Authority, in their capacity as co-owners of the Summer Nuclear Station, filed a breach of contract claim against the DOE in the U.S. Court of Claims. On January 9, 2006, SCE&G, the Authority and the United States Department of Justice entered into a formal written settlement agreement that resolved all issues in the litigation pending in the U.S. Court of Claims and resulted in the dismissal of that litigation with prejudice. Among other things, the agreement provides for the payment of $9,000,000 to SCE&G and the Authority for costs they would not have had to incur but for the delay by the DOE in performing its obligations under the Standard Contract. On a prospective basis, the agreement provides a mechanism for SCE&G and the Authority to recover additional costs associated with any further delay by the DOE in performing its obligations under the Standard Contract.

Fuel Costs

The Authority's rates include various fuel adjustment provisions. Base fuel charges are adjusted to reflect actual fuel costs on a monthly basis for Central and on a three month moving average for most other customers.

Coal and natural gas prices have declined from the high prices seen in 2008 and are currently stable. 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. Coal prices spiked in 2008. In order to offset the impact on the customer, the Authority purchased additional spot coal at lower than normal prices in 2009 and 2010 thereby increasing its inventory levels. Coal inventory levels have remained high as a result of reduced usage of the Authority's coal plants due to lower gas prices, the impact the recession has had on the economy, and recent mild weather conditions.

The Authority forecasts coal prices to remain stable in 2013 and beyond if market trends continue. The Authority continues to monitor market trends, work with vendors, and make purchases when opportunities arise while maintaining stockpile levels. The Authority's current rail transportation contract extends through 2015.

The Energy Authority

The Authority is a member of TEA along with the 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") and Public Utility District No. 1 of Cowlitz County, Washington.

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. 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 the 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 ("FMPA"), Gainesville Regional Utilities, JEA, MEAG Power, NPPD and Orlando Utilities Commission ("OUC").

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.

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. On September 11, 2012, the Authority's Board of Directors approved a series of two base rate adjustments. The adjustments will increase total charges for customers an average 3.5 percent each year for a total increase of 7% 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, the Capital Improvement Fund, and all other such costs as necessary. The first adjustment took effect December 1, 2012 and the second will take 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, 2012, the Authority had 831 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 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 this 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.

During 2012 revenues from sales to wholesale requirements customers averaged 7.33 cents per kWh, revenues from sales to large industrial customers averaged 5.19 cents per kWh, and revenues from sales to residential, commercial, small industrial and other customers averaged 9.19 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, 2012 and January 31, 2013 are set forth on the following page.

As of July 31, 2012 (Summer)

	Residential Electric Service			
	500 kWh	1,000 kWh	2,000 kWh	3,000 kWh
Authority	$58.30	$106.60	$203.20	$299.80
Duke Energy Carolinas	54.76	102.22	205.38	308.55
Progress Energy Carolinas	54.70	102.90	199.30	295.70
SCE&G	69.49	132.91	267.02	401.13

	Commercial Electric Service		
	3,000 kWh	5,000 kWh	7,500 kWh
Authority	$277.90	$456.50	$679.75
Duke Energy Carolinas	277.48	458.85	663.23
Progress Energy Carolinas	299.39	451.69	641.32
SCE&G	382.08	639.32	960.87

	Industrial Electric Service			
	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	$37,310.50	$72,221.00	$337,252.50	$1,605,400.00
Duke Energy Carolinas	31,340.54	59,776.52	284,126.54	1,397,637.57
Progress Energy Carolinas	35,805.00	71,185.00	339,305.00	1,595,225.00
SCE&G	39,465.00	77,130.00	364,570.00	1,746,250.00

As of January 31, 2013 (Non-Summer)

	Residential Electric Service			
	500 kWh	1,000 kWh	2,000 kWh	3,000 kWh
Authority	$58.19	$104.38	$196.76	$289.14
Duke Energy Carolinas	51.12	94.96	190.86	286.76
Progress Energy Carolinas	54.30	100.10	185.70	271.30
SCE&G	73.49	136.44	259.24	382.04

	Commercial Electric Service		
	3,000 kWh	5,000 kWh	7,500 kWh
Authority	$265.14	$431.90	$640.35
Duke Energy Carolinas	256.32	423.58	610.34
Progress Energy Carolinas	297.59	447.69	635.32
SCE&G	393.03	626.75	918.90

	Industrial Electric Service			
	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	$35,927.66	$69,055.32	$319,888.94	$1,517,306.40
Duke Energy Carolinas	28,270.04	53,635.52	253,421.54	1,244,112.57
Progress Energy Carolinas	35,405.00	70,385.00	335,305.00	1,575,225.00
SCE&G	41,760.00	81,595.00	385,515.00	1,846,075.00

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 2003 through 2012.

	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
2003	5,396	12.0	24,060	0.0	1,033,500	1.4	4.30
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
Annual Compound Growth Rate (2003-2012)		0.0		1.2		6.8	

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

The following tables set forth sales and revenues by customer class for the years 2008 through 2012.

Sales (GWh)

	Year									
	2008		2009		2010		2011		2012	
Class of Customers		% of Total		% of Total		% of Total		% of Total		% of Total
Wholesale	15,511	58.1	15,607	60.5	17,231	61.1	16,263	59.0	15,604	58.3
Large Industrial	7,478	28.0	6,501	25.2	6,953	24.7	7,443	27.0	7,509	28.1
Residential, Commercial, Small Industrial and Other .	3,698	13.9	3,705	14.3	3,998	14.2	3,845	14.0	3,643	13.6
Total	26,687	100.0	25,813	100.0	28,182	100.0	27,551	100.0	26,756	100.0

	Year									
	2008		2009		2010		2011		2012	
Class of Customers		% of Total		% of Total		% of Total		% of Total		% of Total
Wholesale	$ 916,860	58.5	$ 1,028,193	61.1	$1,142,582	60.9	$1,129,445	59.6	$1,144,223	61.2
Large Industrial	59,712	22.9	346,318	20.6	376,247	20.1	415,309	21.9	389,742	20.9
Residential, Commercial, Small Industrial and Other .	292,046	18.6	308,958	18.3	308,958	18.3	350,093	18.5	334,843	17.9
Total	$1,568,618	100.0	$1,683,469	100.0	$1,875,264	100.0	$1,894,847	100.0	$1,868,808	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 2008 through 2012 is set forth below:

	Calendar Year (Dollars in Thousands)				
	2012	2011	2010	2009	2008
Operating Revenues	$1,887,797	$1,914,689	$1,894,902	$1,702,001	$1,586,303
Other Income(1)	9,025	8,081	126	3,946	13,666
Total	1,896,822	$1,922,770	$1,895,028	$1,705,947	$1,599,969
Operating Expenses(2)	1,379,158	1,366,423	1,318,814	1,201,140	1,121,693
Revenues Available for Debt Service, Lease Payments and Other Purposes	517,664	556,347	576,214	504,807	478,276
Debt Service on Revenue Bonds(3)	0	0	0	3,298	6,878
Balance Available for Revenue Obligations, Lease Payments and Other Purposes	517,664	556,347	576,214	501,509	471,398
Debt Service on Revenue Obligations(4)	356,852	342,621	362,506	339,875	276,464
Balance Available for Lease Payments and Other Purposes	160,812	213,726	213,708	161,634	194,934
Debt Service on Lease Payments	1,346	1,559	1,936	2,664	3,014
Balance Available for Other Purposes	$ 159,466	$ 212,167	$ 211,772	$ 158,970	$ 191,920
Debt Service Coverage(5):					
Revenue Bonds, Revenue Obligations and Lease Payments	1.44	1.61	1.58	1.45	1.67

(1) Excludes gains on sale of leased lots or rail cars and includes interest subsidy payments for the 2010 Build America Bonds ("BABs").
(2) Excludes 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 2013M1 BONDS - Rate Covenant."
(5) Calculation of coverage does not include debt service on Commercial Paper Notes.

CAPITAL IMPROVEMENT PROGRAM

General

While the Authority regularly reviews its capital improvement program, in its most recent financial projections, the Authority's capital improvement program for years 2013 through 2015 consists of a portion of two future nuclear units and general improvements to the Authority's System, including improvements to existing power supply facilities, extensions of and improvements to transmission and distribution facilities, environmental compliance, and other improvements to general facilities.

The total cost of the capital improvement program in years 2013 through 2015 is estimated to be approximately $2,829,000,000, which includes approximately $2,026,000,000 for a portion of two future nuclear units based on 45% ownership, approximately $165,000,000 for environmental compliance expenditures, and approximately $638,000,000 for general improvements to the System. 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. The Authority reviews, from time to time, its power resources and requirements and considers the possible addition of new power resources.

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 - - Power Resources") and will seek to reduce its level of participation in the two new units at Summer Nuclear Station ("Summer 2" and "Summer 3") from 45% to approximately 20%. See CAPITAL IMPROVEMENT PROGRAM - - Future Nuclear Units."

Future Nuclear Units

In March 2008, the Authority and SCE&G submitted to the NRC an application for Combined Construction and Operating Licenses ("COLs") for two new nuclear units at Summer Nuclear Station. On, March 30, 2012, the NRC concluded its mandatory hearing process on 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 the Authority on March 30, 2012.

The NRC's findings concluding the mandatory hearing imposed two conditions on the COLs, with the first requiring inspection and testing of squib valves, important components of the new reactors' 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.

Summer 2 and Summer 3 will be constructed at an existing nuclear facility which is 400 feet above sea level and approximately 150 miles from the coast. SCE&G, acting for itself and as agent for the Authority, entered into an Engineering, Procurement and Construction ("EPC") Agreement with Westinghouse and Stone & Webster, Inc. for the engineering, procurement, and construction of two 1100 MW nuclear generating units utilizing Westinghouse's AP1000 nuclear reactor design. The Authority currently estimates the total construction cost associated with a 45% ownership interest in the two new nuclear units to be approximately $5.1 billion including related transmission and initial fuel core; of this, $4.7 billion is generation construction cost. The Authority's Board of Directors has authorized the Authority to expend the total estimated construction cost on the nuclear project.

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 the two units. 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. Together, the Design and Construction Agreement and the Operating and Decommissioning Agreement replace the Amended and Restated Bridge Agreement the Authority and SCE&G executed on May 23, 2008. The Authority anticipates that Summer 2 will go into service in March 2017. The Authority anticipates Summer 3 will go into service in May 2018.

As described under "CAPITAL IMPROVEMENT PROGRAM - Long Term Power Supply", the Authority has evaluated its level of participation in a portion of the two future nuclear units and would like to retain about 20 percent ownership. The Authority is engaged in active negotiations with Duke Energy Carolinas LLC to purchase a portion of the Authority's ownership interest in Summer 2 and Summer 3. The Authority is actively exploring other opportunities to market ownership interests in the units to potential buyers.

The Authority filed Part I and Part II applications with the DOE under the DOE's Loan Guarantee Program for nuclear facilities. The Authority is requesting a DOE loan guarantee for its portion of the nuclear project costs. On May 5, 2009, the Authority was notified by the DOE that the VC Summer nuclear project and the Authority had been selected for further due diligence and negotiations leading to a conditional commitment. Further due diligence has commenced. The Authority does not know, at this time, whether it will obtain a loan guarantee.

Individuals opposed to nuclear power could challenge the Authority's attempts to pursue the nuclear project. The Authority intends to pursue the project notwithstanding opposition.

Biomass Projects

The Authority has purchase power agreements with EDF Renewable Energy ("EDF") for 35.6 MWs of biomass-fueled energy and Green Energy Solutions, LLC ("GES") for up to 25 MWs of biogas-fueled energy from multiple facilities. The Authority has also entered into three small power purchase agreements totaling 3.3 MWs for biogas-fueled energy.

The EDF contracts have thirty year terms and the plants are under construction in the counties of Allendale and Dorchester and expected to be online in 2013. The GES contract has a 28 year delivery period and the facilities are planned to be built over the next six years at various sites across the State.

General Improvements

The Authority's general improvement program consists primarily of extensions and improvements to the Authority's existing generating facilities, transmission and distribution systems, and general plant.

Regional Water Systems

Pursuant to the Act, the Authority is permitted to construct, own and operate facilities to treat, transmit and sell potable 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 sells water at wholesale from the Lake Moultrie System to the Lake Moultrie Water Agency, a joint municipal water system consisting of four governmental entities. The Lake Moultrie System treatment plant has a permitted capacity of 36 million gallons per day.

The Authority sells water at wholesale from the Lake Marion Regional Water System to the Lake Marion Regional Water Agency, a joint municipal water system consisting of five governmental entities. The treatment plant portion of the water system was completed and declared commercial on May 1, 2008, and further development of the system is ongoing.

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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 and commercial 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 2013M1 Bonds should obtain and review such information.

FERC Matters

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 preliminary license application was submitted to stakeholders for review in March 2003 and 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 a Ready for Environmental Analysis notice in March 2006. The FERC also has revised its National Environmental Policy Act scoping document from an Environmental Assessment to an Environmental Impact Statement ("EIS") due in part to the size and complexity of the Authority project. The FERC issued its Final 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. NOAA Fisheries 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. On July 15, 2010 National Marine Fisheries Service 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 cannot predict when the FERC may resolve the issue or the final outcome. The Authority submitted a response on September 10, 2010. Negotiations continue between the Authority and the National Marine Fisheries Service in an effort to find alternatives to the draft biological opinion which would meet the biological needs of the shortnose sturgeon.

Environmental Matters

Both federal and State regulatory agencies have imposed various environmental control requirements affecting the Authority's facilities. These requirements relate primarily to airborne pollution, the discharge of pollutants into waters and the disposal of hazardous wastes. Standards related to environmental controls are subject to change, and litigation by environmental groups and others may affect the construction of facilities or their operation. The Authority endeavors to ensure that 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 authorizations and permits will be received, or that standards as to environmental suitability will not be changed in a manner which will affect adversely the Authority or its operations. As described in "POWER SUPPLY AND POWER MARKETING - Power Resources" the Authority has decided it will retire some existing generating units because it would not be cost effective to implement new required environmental measures. The Authority cannot now estimate the precise effect of existing and potential regulations and legislation upon any of its other existing and proposed facilities and operations, nor the impact of additional costs which may be incurred in effecting compliance with potential regulations and legislation.

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. The 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 has 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.

On June 15, 2005, the EPA finalized amendments to the July 1999 regional haze rule. These amendments apply to the provisions of the regional haze rule that require emission controls known as best available retrofit technology ("BART") for industrial facilities emitting air pollutants that reduce visibility by causing or contributing to regional haze. The Authority has submitted to the DHEC a BART dispersion modeling demonstration that shows that BART-eligible sources owned/operated by the Authority are exempt from further BART determination. The DHEC has approved this demonstration and has included the exemption in their SIP submittal. The DHEC has recently proposed their five-year update to the regional haze portion of their SIP. This update has included the closure of Grainger Station Units Nos. 1 and 2 and Jefferies Station Units Nos. 1, 2, 3 and 4 along with the SO_2 control device improvements on Winyah Generating Units Nos. 1 and 2. The DHEC update assumes the Grainger and Jefferies Generating Units will be shut down by 2018. Jefferies Generating Units Nos. 1 and 2 are still operational.

The EPA has promulgated regulations designed to prevent significant deterioration of air quality in portions of a state where air quality is now better than the NAAQS. Winyah Units 3 and 4, Cross Station, Rainey Station, Hilton Head Turbine No. 3 and the Lee County Landfill Generation Facility are subject to and, the Authority believes, are in compliance with the Prevention of Significant Deterioration ("PSD") regulations. Subsequently completed generating facilities will also be subject to the PSD regulations.

The Authority maintains operating permits for each of its existing generating facilities and believes these facilities are operating in compliance with the requirements of the permits. Title V operating permits are maintained for the Rainey, Cross, Winyah, Grainger and Jefferies Generating Stations, the Hilton Head and Myrtle Beach Turbine sites, and the landfill gas generating facilities located at the Horry County, Lee County, Richland County, and Anderson County Landfills. The new Berkeley County Landfill facility is currently operating under a state construction permit until the Title V operating permit is issued by the DHEC. The Georgetown County Landfill facility is operating under a State-Only operating permit.

Congress has enacted comprehensive amendments to the 1990 CAA, including the addition of a new federal Acid Rain program to deal with acid precipitation. The Authority has evaluated the potential impact of this legislation, including new limits on the allowable rates of emission of SO_2 and NO_x beginning in 2000 for boilers. To comply with these regulations, the Authority has purchased SO_2 emission credits and upgraded the sulfur removal capabilities of existing units to meet SO_2 emission limitations. To meet acid rain NOx limits, the Authority retrofitted the combustion systems on some of its boilers with NO_x control technology. In addition, the Authority has installed continuous emission monitoring equipment to comply with monitoring requirements. The Authority continues to be subject to the Acid Rain program.

The EPA has promulgated the Clean Air Interstate Rule (the "CAIR"). The CAIR, which addresses SO_2 and NO_x emissions, was published in the federal register May 12, 2005 and took effect July 11, 2005. Since 2009, the CAIR limits for NO_x went into effect for both annual and ozone season, and the Authority has been operating its system accordingly. Since 2010, the CAIR SO_2 limits went into effect, and the Authority has been operating its system accordingly. 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 January 10, 2012, the EPA returned the vintage 2012 CAIR allowances to allowance accounts. By January 26, 2012, the EPA signed a notice indicating the Agency would not require compliance with CSAPR supplemental rule while the stay was in effect. On February 7, 2012, the EPA issued two sets of minor adjustments to the CSAPR. On March 1, 2012, the EPA filed its brief on the merits of the legal challenges to CSAPR. As of April 20, 2012, the EPA has reviewed comments submitted in response to the Direct Final Revisions Rule, and indicated that they intend to withdraw the Direct Final Revisions Rule prior to its effective date and take final action on the proposed revisions rule expeditiously. On August 21, 2012, the U.S. Court of Appeals for the D.C. Circuit issued its ruling vacating CSAPR. CAIR was remanded to the EPA by the court but still remains in effect until a replacement rule is finalized. The EPA appealed the court's ruling on October 5, 2012. The U.S. Court of Appeals for the D.C. Circuit denied the EPA's appeal on January 24, 2013.

On May 3, 2011, the EPA issued a proposed rule for National Emission Standards for Hazardous Air Pollutants ("NESHAPs") from Coal and Oil-Fired Electric Utility Steam Generating Units and proposed to revise the NSPS for Fossil-Fuel-Fired Electric Utility Industrial-Commercial-Institutional and Small Industrial-Commercial-Institutional Steam Generating Units. The NESHAP portion of this proposed rule proposes Maximum Achievable Control Technology emissions limitations for mercury, non-mercury metallic hazardous air pollutants, and acid gases also referred to as the Utility MACT. The revised NSPS portion of this proposed rule proposes Best Demonstrated Technology emission standards for PM, SO_2 and NO_x. The Authority has submitted comments on this proposed rule. On December 21, 2011, the EPA issued a draft rule that was published in the Federal Register February 16, 2012, and renamed the Mercury and Air Toxics Standard ("MATS") for power plants. Although somewhat less stringent than the proposed rule, MATS will have significant impacts on the Authority's coal-fired units. The Authority is still evaluating the impact of this rule, which became effective, April 16, 2012, with a compliance deadline of April 16, 2015.

The CAA requires that air quality in every state meet health based NAAQS. The most recent national ambient air quality standard for ozone was issued March 12, 2008 and is stricter than the previous standard. The most recent national ambient air quality standard for nitrogen dioxide was issued February 9, 2010 (effective April 12, 2010) and is stricter than the previous standard. The most recent national ambient air quality standard for SO_2 was issued June 22, 2010 and is stricter than the previous standard. The Authority is following these regulatory changes and is evaluating the impact from these revised NAAQS standards.

The EPA announced September 21, 2006 that it was revising the NAAQS to tighten the daily standard on PM 2.5. The new rule on PM 2.5 went into effect on December 18, 2006. It lowered the 24-hour standard for PM 2.5 to 35 micrograms per cubic meter, nearly cutting in half the current standard of 65 micrograms per cubic meter. The annual standard for PM 2.5 remained at the level the agency set in 1997. States must begin implementation of the PM2.5 standard in 2011. The areas in which the Authority's facilities are located in are currently in compliance with this standard. The EPA promulgated a final rule on PM 2.5 on December 14, 2012. The annual standard was reduced but the 24-hour standard remained the same. All of the state of South Carolina is currently in attainment with the new standard.

Greenhouse Gases. The EPA is proposing NSPS for emissions of carbon dioxide ("CO_2") for new affected fossil fuel-fired electric utility generating units ("EGUs"). The EPA is proposing these requirements because CO_2 is a greenhouse gas ("GHG") and fossil fuel-fired power plants are the country's largest 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.

On May 13, 2010, the EPA issued the final rule for GHG emissions that "tailors" both the PSD program and Title V program for greenhouse gas emissions (the "Tailoring Rule"). Under this rule, the following dates and limits will apply:

1) January 2, 2011 through June 30, 2011: Existing PSD sources undertaking projects that will increase GHG emissions in excess of 75,000 tons per year will be subject to the PSD review for GHGs and would require implementation of Best Available Control Technology for the emission source. In a similar manner, existing Title V sources will be subjected to Title V requirements for GHGs if a project exceeds 75,000 TPY GHGs.

2) July 1, 2011 through June 30, 2013: In addition to step one above, any source that undertakes a new project that exceeds 100,000 TPY of GHG emissions will be subject to PSD and Title V requirements.

The Authority, along with 24 other petitioners, has filed a petition for review of the Tailoring Rule.

Congress continues to consider legislation that will reduce GHG emissions from major sources, including electric utilities, as well as implementation of other complementary measures to reduce GHG emissions.

On September 22, 2009, the EPA announced a final rule on the new GHG reporting program. Beginning January 1, 2010, the Authority is 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. The first annual report for the calendar year 2010 was submitted to the EPA by the September 30, 2011 regulatory deadline. The second annual report for reporting 2011 GHG emissions was submitted by the March 31, 2012 deadline. Additional reporting was required under Subpart DD of the rule for Electric Transmission & Distribution Equipment and was submitted by the EPA deadline of September 30, 2012. This rule is commonly referred to as the Greenhouse Gas Mandatory Reporting Rule ("GHG-MRR").

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 status of the Authority's permits is shown below:

Facility	Permit Type	Effective Date	Expiration Date	Renewal Application Date
Cross Generating Station	Individual	Nov. 3, 2006	Aug. 31, 2010	Mar. 4, 2010
Grainger Generating Station	Individual	Oct. 1, 2002	Sep. 30, 2006	Mar. 28, 2006
Jefferies Generating Station	Individual	Mar. 1, 2003	Feb. 29, 2008	Aug. 30, 2007
Rainey Generating Station	Individual	May 1, 2013	Apr. 30, 2018	Oct. 31, 2017
Winyah Generating Station	Individual	Mar. 1, 2007	Jul. 31, 2011	Feb. 1, 2011
Regional Water Systems	General	Nov. 1, 2010	Oct. 30, 2015	May 3, 2015

Although several of the Authority's NPDES Permits contain expiration dates which have passed, the permits continue to be in effect pursuant to Section 1-23-370 of the Code of Laws in South Carolina 1976, as amended, as long as timely re-applications were received pursuant to Regulation 61-9.122.6. As shown in the above Table, permit applications were submitted within the 180 day time frame required by S.C. Regulation 61-9, Section 122.21 (D).

The DHEC reissued the "NPDES General Permit for Storm Water Discharges Associated With Industrial Activities (Industrial General Permit)" on November 12, 2010 with an effective date of January 1, 2011 and an expiration date of January 1, 2016. The new Permit (SCR000000) has specific requirements for various industrial sectors based on Standard Industrial Classification Codes, including landfills and steam electric generating stations. As required under the new permit, NOIs were submitted and revised Stormwater Pollution Prevention Plans were implemented for all Generating Stations to provide coverage under this permit.

The DHEC has also reissued the "NPDES General Permit for Storm Water Discharges from Construction Activities" ("CGP") on October 15, 2012 with an effective date of January 1, 2013. The new permit (SCR100000) is a major restructuring of the 2006 CGP in how the requirements are presented. The Authority is reviewing the new permit in preparation for the implementation of any new or changed requirements.

Section 316(b) of the Clean Water Act 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 new draft rule in the Federal Register on April 20, 2011. Compliance dates are geared to the time the EPA issues the final rule, which must be signed by July 27, 2013 under a modified settlement agreement. The Authority is reviewing the draft rule to determine the potential impact to the Authority's generating facilities.

Industrial Solid Waste Landfills. At Cross Generating Station, dry disposal of coal combustion residuals ("CCRs") into an industrial Class 2 solid waste landfill is governed by a Consent Agreement executed on April 29, 2011 between the Authority and the DHEC, which provides for operation of the landfill until December 31, 2015.

The Authority is continuing work on permitting additional Class 3 landfills at the Cross facility. On June 13, 2011, the DHEC published a Notice of Department Decision that the proposed Authority Cross Generating Station Class 3 Landfill meets the requirements set forth in Part I, Section D.1. of Regulation 61-107.19. On October 31, 2011, the Authority submitted a Siting Study and Hydrogeologic Site Characterization to the DHEC for approval. DHEC served notice on April 25, 2012 that the site has been deemed suitable and all requirements of the Landfill Siting Study and Site Hydrologic Characterization for site suitability have been met.

On January 12, 2012 the Department of Army issued a Section 404 permit authorizing 67.3 acres of wetlands impacts for the landfill project; and, on September 15, 2011 the DHEC Ocean and Coastal Resource Management issued a Section 401 Water Quality and Coastal Zone Management Act Consistency Certification. The Authority submitted a landfill permit application to DHEC on March 2, 2012.

Spill Prevention Control and Countermeasures. The EPA revised and finalized sections of the CWA relating to Spill Prevention Control and Counter- measures ("SPCC") on December 26, 2006. These revisions require that regulated facilities, including generating stations, substations and auxiliary facilities, amend their SPCC plans to meet the new standard which became effective November 10, 2011. The Authority endeavors to manage all applicable facilities in accordance with the rule and as required under each facility's SPCC plan.

Safe Drinking Water Act. The Authority continues to monitor for Safe Drinking Water Act regulatory issues impacting drinking water systems as the Authority's Regional Water Systems, generating stations, substations and other auxiliary facilities. The 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. The Authority endeavors to manage its potable water systems for compliance with R.61-58.

Hazardous Substances and Wastes. Section 311 of the CWA 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") provides for the reporting requirements to cover the release of hazardous substances generally into the environment, including water, land and air. When these substances are processed, stored, or handled, reasonable and prudent methods are employed to prevent a release to the environment.

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.

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. CERCLA liability, which is strict, joint and several, can be imposed on any generator of hazardous substances who arranged for disposal or treatment at the affected facility. 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 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. 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 and scrubber sludge. These wastes are exempt from hazardous wastes regulation under the Resource Conservation and Recovery Act ("RCRA"). However, on June 21, 2010, the EPA issued a proposed rule to regulate CCRs under RCRA. No estimate relative to the cost of implementing any new regulations, when promulgated, can be made at this time.

Certain waste including spent boiler cleaning solutions, waste solvents and certain waste oils may be considered hazardous wastes. The Authority endeavors to maintain compliance with the RCRA and South Carolina Hazardous Waste Management regulations and believes its facilities are currently operating substantially in compliance with the regulations.

Also under RCRA, the Authority may be required to undertake corrective action with respect to any leaking underground petroleum storage tank and is liable for the costs of any corrective action taken by the EPA, including compensating third parties for personal injuries and property damage. The Authority is required by the EPA and the DHEC to maintain documentation of sufficient funds or insurance to cover environmental impacts. The Authority is required to register each underground petroleum tank with the DHEC and obtain permits to operate on an annual basis. Operation of these tanks is governed by both state and federal regulations with daily monitoring of inventory, recording of maintenance, and inspections of equipment to ensure tightness of the system and prohibit releases into the environment. The EPA and the DHEC have implemented a certification program for operators of these tanks with which the Authority will comply.

Homeland Security. The Department of Homeland Security (the "DHS") has promulgated regulations under the Homeland Security Act of 2002 relating to anti-terrorism standards at major industrial facilities. Facilities that store or process chemicals in quantities exceeding established thresholds must submit a screening assessment to the DHS. Based on these assessments, the DHS may impose additional requirements, including a security vulnerability assessment and a Site Security Plan ("SSP"). The Authority submitted screening assessments for Cross, Winyah, and Jefferies Generating Stations. The Authority later completed a security vulnerability assessment for Jefferies Station which was submitted by the compliance date of October 18, 2010. The Authority has been proactive in conducting security assessments independently and with guidance from the DHS since 2001, and will continue to comply with this new and evolving body of regulations.

Nuclear Matters

The Summer Nuclear Station 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 the Summer Nuclear Station 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 $195 million at December 31, 2012, along with future deposits into both the internal and external funds and investment earnings, are estimated to provide sufficient funds for the Authority's one-third share of the total estimated decommissioning costs.

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. The Authority has 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 has also paid an additional $10.4 million in costs and attorneys’ fees to the plaintiffs. 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 indemnification 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. If the Corps chooses to appeal the ASBCA decision, its appeal must be filed on or before June 19, 2013. The Authority cannot predict whether the Corps will appeal the decision.

Grainger Ash Pond Litigation. Several environmental advocacy groups filed suit against the Authority in the Court of Common Pleas in Horry County in June 2012 seeking injunctive relief with regard to closure of ash ponds at the Grainger Generating Station. The suit does not seek damages but alleges that an unlawful discharge of arsenic and other contaminants has occurred and requests that the court order the removal and offsite storage of all ash contained in the ponds. The Authority has filed an Answer to the suit and is defending against the allegations. The Authority intends to properly close the ash ponds in accordance with regulatory requirements.

On April 29, 2013, Winyah Rivers Foundation filed a Clean Water Act Suit against the Authority in the Charleston Division of the United States District Court. The suit alleges violations of the federal Clean Water Act at the Grainger Generating Station and seeks injunctive relief, civil penalties, and costs and attorneys’ fees. The Authority is unable to determine at this time whether a court would assess civil penalties, or if assessed the amount of civil penalties.

The Authority presented an conceptual plan for closure of the Grainger Generating Station ash ponds to the DHEC on March 18, 2013. The preliminary estimate for closure of the ash ponds pursuant to the conceptual plan is $37.8 million. This estimate has been recognized as a regulatory liability on the Authority’s audited reports.

FINANCIAL ADVISOR

The Authority has retained Public Financial Management, Inc., as Financial Advisor in connection with the issuance of the 2013M1 Bonds.

TAX MATTERS

Federal Income Tax Generally

On the date of issuance of the 2013M1 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 2013M1 Bonds is excludable from the gross income of the registered owners thereof for federal income tax purposes. Interest on the 2013M1 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 2013M1 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 2013M1 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 2013M1 Bonds and the tax-exempt status of interest on the 2013M1 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 2013M1 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 2013M1 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 2013M1 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 2013M1 Bonds in gross income for federal income tax purposes retroactive to the date of issuance of the 2013M1 Bonds. The opinion of Bond Counsel delivered on the date of issuance of the 2013M1 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 2013M1 Bonds.

Collateral Federal Tax Considerations

Prospective purchasers of the 2013M1 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. Bond Counsel expresses no opinion concerning such collateral income tax consequences, and prospective purchasers of 2013M1 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 2013M1 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 2013M1 Bonds. No prediction can be made concerning future legislation which if passed might adversely affect the tax treatment of interest on the 2013M1 Bonds. Prospective purchasers of the 2013M1 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 2013M1 Bonds. Bond Counsel's engagement with respect to the 2013M1 Bonds ends with the issuance of the 2013M1 Bonds and unless separately engaged, Bond Counsel is not obligated to defend the Authority or the owners of 2013M1 Bonds regarding the tax-exempt status of the 2013M1 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 2013M1 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 2013M1 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 2013M1 Bonds, and may cause the Authority or the owners of 2013M1 Bonds to incur significant expense, regardless of the ultimate outcome.

State Tax Exemption

Bond Counsel is of the further opinion that the 2013M1 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 2013M1 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 2013M1 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 2013M1 Bonds. Such opinion will be attached to the 2013M1 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.

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MISCELLANEOUS

The agreements of the Authority with the owners of the 2013M1 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 2013M1 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/ Elaine G Peterson
Executive Vice President and
Chief Financial Officer