SCANA CORP
Form 10-Q
August 08, 2013
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549
FORM 10-Q

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended June 30, 2013

OR

¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Transition Period from to

Commission File Number	Registrant, State of Incorporation, Address and Telephone Number	I.R.S. Employer Identification No.
1-8809	SCANA Corporation (a South Carolina corporation) 100 SCANA Parkway, Cayce, South Carolina 29033 (803) 217-9000	57-0784499
1-3375	South Carolina Electric & Gas Company (a South Carolina corporation) 100 SCANA Parkway, Cayce, South Carolina 29033 (803) 217-9000	57-0248695

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. SCANA Corporation Yes x No ¨ South Carolina Electric & Gas Company Yes x No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). SCANA Corporation Yes x No ¨ South Carolina Electric & Gas Company Yes x No ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act.

SCANA Corporation	Large accelerated filer x Smaller reporting company ¨	Accelerated filer ¨	Non-accelerated filer ¨
South Carolina Electric & Gas Company	Large accelerated filer ¨ Smaller reporting company ¨	Accelerated filer ¨	Non-accelerated filer x

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

SCANA Corporation Yes ¨ No x South Carolina Electric & Gas Company Yes ¨ No x

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Registrant	Description of Common Stock	Shares Outstanding at July 31, 2013
SCANA Corporation	Without Par Value	139,985,242
South Carolina Electric & Gas Company	Without Par Value	40,296,147 (a)

(a) Held beneficially and of record by SCANA Corporation.

This combined Form 10-Q is separately filed by SCANA Corporation and South Carolina Electric & Gas Company. Information contained herein relating to any individual company is filed by such company on its own behalf. Each company makes no representation as to information relating to the other company.

South Carolina Electric & Gas Company meets the conditions set forth in General Instruction H(1)(a) and (b) of Form 10-Q and therefore is filing this Form with the reduced disclosure format allowed under General Instruction H(2).

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

Statements included in this Quarterly Report on Form 10-Q which are not statements of historical fact are intended to be, and are hereby identified as, “forward-looking statements” for purposes of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements include, but are not limited to, statements concerning key earnings drivers, customer growth, environmental regulations and expenditures, leverage ratio, projections for pension fund contributions, financing activities, access to sources of capital, impacts of the adoption of new accounting rules and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as “may,” “will,” “could,” “should,” “expects,” “forecasts,” “plans,” “anticipates,” “believes,” “estimates,” “projects,” “predicts,” “potential” or “continue negative of these terms or other similar terminology. Readers are cautioned that any such forward-looking statements are not guarantees of future performance and involve a number of risks and uncertainties, and that actual results could differ materially from those indicated by such forward-looking statements. Important factors that could cause actual results to differ materially from those indicated by such forward-looking statements include, but are not limited to, the following:

(1) the information is of a preliminary nature and may be subject to further and/or continuing review and adjustment;
(2) regulatory actions, particularly changes in rate regulation, regulations governing electric grid reliability, environmental regulations, and actions affecting the construction of new nuclear units;
(3) current and future litigation;
(4) changes in the economy, especially in areas served by subsidiaries of SCANA;
(5) the impact of competition from other energy suppliers, including competition from alternate fuels in industrial markets;
(6) the impact of conservation and demand side management efforts and/or technological advances on customer usage;
(7) growth opportunities for SCANA’s regulated and diversified subsidiaries;
(8) the results of short- and long-term financing efforts, including prospects for obtaining access to capital markets and other sources of liquidity;
(9) changes in SCANA’s or its subsidiaries’ accounting rules and accounting policies;
(10) the effects of weather, especially in areas where the generation and transmission facilities of SCANA and its subsidiaries (the Company) are located and in areas served by SCANA’s subsidiaries;
(11) payment and performance by counterparties and customers as contracted and when due;
(12) the results of efforts to license, site, construct and finance facilities for electric generation and transmission;
(13) maintaining creditworthy joint owners for SCE&G’s new nuclear generation project;
(14) the ability of suppliers, both domestic and international, to timely provide the labor, components, parts, tools, equipment and other supplies needed, at agreed upon prices, for our construction program, operations and maintenance;
(15) the results of efforts to ensure the physical and cyber security of key assets and processes;
(16) the availability of fuels such as coal, natural gas and enriched uranium used to produce electricity; the availability of purchased power and natural gas for distribution; the level and volatility of future market prices for such fuels and purchased power; and the ability to recover the costs for such fuels and purchased power;
(17) the availability of skilled and experienced human resources to properly manage, operate, and grow the Company’s businesses;
(18) labor disputes;
(19) performance of SCANA’s pension plan assets;
(20) changes in taxes;
(21) inflation or deflation;
(22) compliance with regulations;
(23) natural disasters and man-made mishaps that directly affect our operations or the regulations governing them; and
(24)

the other risks and uncertainties described from time to time in the periodic reports filed by SCANA or SCE&G with the SEC.

SCANA and SCE&G disclaim any obligation to update any forward-looking statements.

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DEFINITIONS

The following abbreviations used in the text have the meanings set forth below unless the context requires otherwise:

TERM	MEANING
AFC	Allowance for Funds Used During Construction
ANI	American Nuclear Insurers
AOCI	Accumulated Other Comprehensive Income
ARO	Asset Retirement Obligation
BACT	Best Available Control Technology
BLRA	Base Load Review Act
CAA	Clean Air Act, as amended
CAIR	Clean Air Interstate Rule
CEO	Chief Executive Officer
CFO	Chief Financial Officer
CGT	Carolina Gas Transmission Corporation
COL	Combined Construction and Operating License
Company	SCANA, together with its consolidated subsidiaries
Consolidated SCE&G	SCE&G and its consolidated affiliates
Consortium	A consortium consisting of Westinghouse Electric Company LLC and Stone and Webster, Inc., a subsidiary of Chicago Bridge & Iron Company N.V.
CSAPR	Cross-State Air Pollution Rule
CUT	Customer Usage Tracker
DHEC	South Carolina Department of Health and Environmental Control
DOJ	United States Department of Justice
DSM Programs	Demand reduction and energy efficiency programs
EIZ Credits	South Carolina Capital Investment Tax Credits (formerly known as Economic Impact Zone Income Tax Credits)
Energy Marketing	The divisions of SEMI, excluding SCANA Energy
EPA	United States Environmental Protection Agency
EPC Contract	Engineering, Procurement and Construction Agreement dated May 23, 2008
eWNA	Pilot Electric Weather Normalization Adjustment
FERC	United States Federal Energy Regulatory Commission
Fuel Company	South Carolina Fuel Company, Inc.
GENCO	South Carolina Generating Company, Inc.
GHG	Greenhouse Gas
GWh	Gigawatt hour
IRP	Integrated Resource Plan
JEDA	South Carolina Jobs-Economic Development Authority
LOC	Lines of Credit
MGP	Manufactured Gas Plant
MMBTU	Million British Thermal Units
MW	Megawatt
NASDAQ	The NASDAQ Stock Market, Inc.
NCUC	North Carolina Utilities Commission
NEIL	Nuclear Electric Insurance Limited
New Units	Nuclear Units 2 and 3 under construction at Summer Station
NRC	United States Nuclear Regulatory Commission

NSPS	New Source Performance Standards
NSR	New Source Review
NYMEX	New York Mercantile Exchange

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OCI	Other Comprehensive Income
ORS	South Carolina Office of Regulatory Staff
PGA	Purchased Gas Adjustment
Price-Anderson	Price-Anderson Indemnification Act
PRP	Potentially Responsible Party
PSNC Energy	Public Service Company of North Carolina, Incorporated
Retail Gas Marketing	SCANA Energy
RSA	Natural Gas Rate Stabilization Act
Santee Cooper	South Carolina Public Service Authority
SCANA	SCANA Corporation, the parent company
SCANA Energy	A division of SEMI which markets natural gas in Georgia
SCE&G	South Carolina Electric & Gas Company
SCEUC	South Carolina Energy Users Committee
SCPSC	Public Service Commission of South Carolina
SEC	United States Securities and Exchange Commission
SEMI	SCANA Energy Marketing, Inc.
Summer Station	V. C. Summer Nuclear Station
VIE	Variable Interest Entity

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SCANA CORPORATION
FINANCIAL SECTION

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PART I. FINANCIAL INFORMATION
Item 1. FINANCIAL STATEMENTS

SCANA CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

Millions of dollars	June 30, 2013	December 31, 2012
Assets		
Utility Plant In Service	$12,037	$11,865
Accumulated Depreciation and Amortization	(3,916)	(3,811)
Construction Work in Progress	2,379	2,084
Plant to be Retired, Net	351	362
Nuclear Fuel, Net of Accumulated Amortization	267	166
Goodwill, net of writedown of $230	230	230
Utility Plant, Net	11,348	10,896
Nonutility Property and Investments:		
Nonutility property, net of accumulated depreciation of $145 and $139	313	306
Assets held in trust, net-nuclear decommissioning	95	94
Other investments	89	87
Nonutility Property and Investments, Net	497	487
Current Assets:		
Cash and cash equivalents	92	72
Receivables, net of allowance for uncollectible accounts of $6 and $7	685	780
Inventories (at average cost):		
Fuel and gas supply	271	304
Materials and supplies	140	136
Emission allowances	1	1
Prepayments and other	218	223
Deferred income taxes	12	11
Total Current Assets	1,419	1,527
Deferred Debits and Other Assets:		
Regulatory assets	1,439	1,464
Other	235	242
Total Deferred Debits and Other Assets	1,674	1,706
Total	$14,938	$14,616

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Millions of dollars	June 30, 2013	December 31, 2012
Capitalization and Liabilities		
Common Equity	$4,506	$4,154
Long-Term Debt, net	5,432	4,949
Total Capitalization	9,938	9,103
Current Liabilities:		
Short-term borrowings	304	623
Current portion of long-term debt	23	172
Accounts payable	401	428
Customer deposits and customer prepayments	79	86
Taxes accrued	101	164
Interest accrued	82	82
Dividends declared	71	66
Derivative financial instruments	14	80
Other	88	110
Total Current Liabilities	1,163	1,811
Deferred Credits and Other Liabilities:		
Deferred income taxes, net	1,698	1,653
Deferred investment tax credits	34	36
Asset retirement obligations	570	561
Postretirement benefits	392	387
Regulatory liabilities	976	882
Other	167	183
Total Deferred Credits and Other Liabilities	3,837	3,702
Commitments and Contingencies (Note 9)	—	—
Total	$14,938	$14,616

See Notes to Condensed Consolidated Financial Statements.

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SCANA CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
Millions of dollars, except per share amounts	2013	2012	2013	2012
Operating Revenues:				
Electric	$610	$592	$1,193	$1,137
Gas - regulated	158	127	540	404
Gas - nonregulated	248	189	594	474
Total Operating Revenues	1,016	908	2,327	2,015
Operating Expenses:				
Fuel used in electric generation	188	198	374	379
Purchased power	9	4	16	10
Gas purchased for resale	310	223	811	588
Other operation and maintenance	171	170	347	345
Depreciation and amortization	94	89	188	178
Other taxes	55	53	109	106
Total Operating Expenses	827	737	1,845	1,606
Operating Income	189	171	482	409
Other Income (Expense):				
Other income	12	12	25	26
Other expense	(10)	(9)	(22)	(19)
Interest charges, net of allowance for borrowed funds used during construction of $3, $3, $5 and $4	(74)	(73)	(148)	(145)
Allowance for equity funds used during construction	6	4	10	7
Total Other Expense	(66)	(66)	(135)	(131)
Income Before Income Tax Expense	123	105	347	278
Income Tax Expense	38	33	110	85
Net Income	$85	$72	$237	$193
Per Common Share Data				
Basic Earnings Per Share of Common Stock	$0.60	$0.55	$1.73	$1.48
Diluted Earnings Per Share of Common Stock	$0.60	$0.54	$1.72	$1.46
Weighted Average Common Shares Outstanding (millions)				
Basic	139.6	130.9	137.0	130.6
Diluted	139.6	133.1	137.9	132.7
Dividends Declared Per Share of Common Stock	$0.5075	$0.495	$1.015	$0.990

See Notes to Condensed Consolidated Financial Statements.

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SCANA CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
Millions of dollars	2013	2012	2013	2012
Net Income	$85	$72	$237	$193
Other Comprehensive Income (Loss), net of tax:				
Unrealized gains (losses) on cash flow hedging activities arising during period, net of tax of $-, $(2), $2 and $(4)	—	(3)	3	(7)
Losses on cash flow hedging activities reclassified to net income, net of tax of $-, $2, $3 and $9	1	4	5	14
Amortization of deferred employee benefit plan costs reclassified to net income, net of tax of $-, $-, $- and $-	1	1	1	1
Other Comprehensive Income	2	2	9	8
Total Comprehensive Income	$87	$74	$246	$201

Accumulated other comprehensive loss totaled $76.4 million as of June 30, 2013 and $85.6 million as of December 31, 2012.

See Notes to Condensed Consolidated Financial Statements.

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SCANA CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Six Months Ended June 30,	
Millions of dollars	2013	2012
Cash Flows From Operating Activities:		
Net income	$237	$193
Adjustments to reconcile net income to net cash provided from operating activities:		
Deferred income taxes, net	39	65
Depreciation and amortization	194	183
Amortization of nuclear fuel	27	26
Allowance for equity funds used during construction	(10)	(7)
Cash provided (used) by changes in certain assets and liabilities:		
Receivables	101	77
Inventories	2	(25)
Prepayments and other	(16)	17
Regulatory liabilities	56	28
Accounts payable	(15)	(32)
Taxes accrued	(63)	(47)
Interest accrued	—	4
Regulatory assets	9	20
Changes in other assets	(45)	(13)
Changes in other liabilities	(23)	(50)
Net Cash Provided From Operating Activities	493	439
Cash Flows From Investing Activities:		
Property additions and construction expenditures	(526)	(591)
Proceeds from investments (including derivative collateral posted)	175	237
Purchase of investments (including derivative collateral posted)	(135)	(211)
Proceeds from interest rate contract settlement	43	13
Payments upon interest rate contract settlement	(49)	(51)
Net Cash Used For Investing Activities	(492)	(603)
Cash Flows From Financing Activities:		
Proceeds from issuance of common stock	247	50
Proceeds from issuance of long-term debt	451	494
Repayment of long-term debt	(223)	(270)
Dividends	(137)	(128)
Short-term borrowings, net	(319)	17
Net Cash Provided From Financing Activities	19	163
Net Increase (Decrease) In Cash and Cash Equivalents	20	(1)
Cash and Cash Equivalents, January 1	72	29
Cash and Cash Equivalents, June 30	$92	$28
Supplemental Cash Flow Information:		
Cash paid for– Interest (net of capitalized interest of $5 and $4)	$144	$141
– Income taxes	43	3
Noncash Investing and Financing Activities:		
Accrued construction expenditures	90	61
Capital leases	5	2
Nuclear fuel purchase	97	—

See Notes to Condensed Consolidated Financial Statements.

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SCANA CORPORATION
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
For the Three and Six Months Ended June 30, 2013 and 2012
(Unaudited)

The following notes should be read in conjunction with the Notes to Consolidated Financial Statements appearing in SCANA's Annual Report on Form 10-K for the year ended December 31, 2012. These are interim financial statements and, due to the seasonality of the Company's business and matters that may occur during the rest of the year, the amounts reported in the Condensed Consolidated Statements of Income are not necessarily indicative of amounts expected for the full year. In the opinion of management, the information furnished herein reflects all adjustments, all of a normal recurring nature, which are necessary for a fair statement of the results for the interim periods reported.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amount of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Plant to be Retired

In 2012, SCE&G announced its intention to retire six coal-fired units by 2018, subject to future developments in environmental regulations, among other matters. These units had an aggregate generating capacity (summer 2012) of 730 MW. One of these units (90 MW) was retired in 2012 and its net carrying value is recorded in regulatory assets as unrecovered plant (see Note 2). In June 2013, SCE&G approved a plan to accelerate the retirement of two more of these units (295 MW) by the end of 2013. The net carrying value of the remaining units to be retired (including these two units) totaled $351 million at June 30, 2013 and is included in Plant to be Retired, Net in the consolidated financial statements. In connection with their retirement, SCE&G expects to be allowed a recovery of and a return on the net carrying value of these remaining units through rates. In the meantime, these units remain in rate base, and SCE&G continues to depreciate them using composite straight-line rates approved by the SCPSC.

Earnings Per Share

The Company computes basic earnings per share by dividing net income by the weighted average number of common shares outstanding for the period. The Company computes diluted earnings per share using this same formula after giving effect to securities considered to be dilutive potential common stock utilizing the treasury stock method. The Company has issued no securities that would have an antidilutive effect on earnings per share.

Reconciliations of the weighted average number of common shares for basic and diluted earnings per share computation purposes are as follows:

	Second Quarter		Year to Date	
Millions	2013	2012	2013	2012
Weighted Average Shares Outstanding - Basic	139.6	130.9	137.0	130.6
Effect of dilutive equity forward shares	—	2.2	0.9	2.1
Weighted Average Shares - Diluted	139.6	133.1	137.9	132.7

Asset Management and Supply Service Agreements

PSNC Energy utilizes asset management and supply service agreements with counterparties for certain natural gas storage facilities. Such counterparties held 40% and 44% of PSNC Energy's natural gas inventory at June 30, 2013 and December 31, 2012, respectively, with a carrying value of $14.1 million and $19.6 million, respectively, through either capacity release or agency relationships. Under the terms of the asset management agreements, PSNC Energy receives storage asset management fees. The agreements expire March 31, 2015.

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2. RATE AND OTHER REGULATORY MATTERS

Rate Matters

Electric

SCE&G's retail electric rates include a cost of fuel component approved by the SCPSC which may be adjusted periodically to reflect changes in the price of fuel purchased by SCE&G. In April 2012, the SCPSC approved SCE&G's request to decrease the total fuel cost component of its retail electric rates, and approved a settlement agreement among SCE&G, the ORS and SCEUC in which SCE&G agreed to recover an amount equal to its actual under-collected balance of base fuel and variable environmental costs as of April 30, 2012, or $80.6 million, over a 12-month period beginning with the first billing cycle of May 2012.

In the December 2012 rate order, the SCPSC authorized SCE&G to reduce the base fuel cost component of its retail electric rates and, in doing so, stated that SCE&G may not adjust its base fuel cost component prior to the last billing cycle of April 2014, except where necessary due to extraordinary unforeseen economic or financial conditions. In February 2013, in connection with its annual review of base rates for fuel costs, SCE&G requested authorization to reduce its environmental fuel cost component effective with the first billing cycle of May 2013. Consistent with the December 2012 rate order, however, SCE&G did not request any adjustment to its base fuel cost component. On March 14, 2013, SCE&G, ORS and the SCEUC entered into a settlement agreement accepting the proposed lower environmental fuel cost component effective with the first billing cycle of May 2013, and providing for the accrual of certain debt-related carrying costs on a portion of the undercollected balance of fuel costs. The SCPSC issued an order dated April 30, 2013, adopting and approving the settlement agreement and approving SCE&G's total fuel cost component.

On December 19, 2012, the SCPSC approved a 4.23% overall increase in SCE&G's retail electric base rates, effective January 1, 2013, and authorized an allowed return on common equity of 10.25%. The SCPSC also approved a mid-period reduction to the cost of fuel component in rates (as discussed above), a reduction in the DSM Programs component rider to retail rates, and the recovery of and a return on the net carrying value of certain retired generating plant assets described below. By order dated February 7, 2013, the SCPSC denied the SCEUC's petition for rehearing of this order.

The eWNA is designed to mitigate the effects of abnormal weather on residential and commercial customers' bills and is based on a 15 year historical average of temperatures. In connection with the December 2012 rate order, SCE&G agreed to perform a study of alternative structures for the eWNA which may be used to modify or terminate eWNA in the future. The study was completed and filed with the SCPSC on June 28, 2013. In the study, SCE&G proposed that no adjustment or modification to the eWNA be made at this time. SCE&G cannot predict what action the SCPSC may take, if any, as a result of this study.

In February 2013, SCE&G filed an IRP with the SCPSC. The IRP evaluates future electric generation needs based on a variety of factors, including customer energy demands, EPA regulations, reserve margins and fuel costs. The IRP identified a total of six coal-fired units that SCE&G retired or intends to retire by 2018, subject to future developments in environmental regulations, among other matters. One of these units was retired in 2012, and its net carrying value is recorded in regulatory assets as unrecovered plant and is being amortized over its original remaining useful life. The net carrying value of the remaining units is included in Plant to be Retired, Net in the consolidated financial statements. In connection with their retirement, SCE&G expects to be allowed a recovery of and a return on the net carrying value of these remaining units through rates. In the meantime, these units remain in rate base, and SCE&G continues to depreciate them using composite straight-line rates approved by the SCPSC. As discussed in Note 1, in June 2013, SCE&G approved a plan to accelerate the retirement of two of the units to be completed by December 31, 2013.

SCE&G's DSM Programs for electric customers provide for an annual rider, approved by the SCPSC, to allow recovery of the costs and net lost revenue associated with the DSM Programs, along with an incentive for investing in such programs. SCE&G submits annual filings in January to the SCPSC regarding the DSM Programs, net lost revenues, program costs, incentives and net program benefits. The SCPSC has approved the following rate changes pursuant to annual DSM Programs filings, which changes became effective as indicated:

Year	Effective	Amount
2012	First billing cycle of May	$19.6 million
2011	First billing cycle of June	$7.0 million

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In January 2013, SCE&G filed its annual update on DSM Programs and a petition for an update to the rate rider requesting an increase of approximately $27.2 million. On April 1, 2013, ORS filed a report of its review of SCE&G's DSM Programs petition with the SCPSC. ORS proposed that SCE&G recover the net lost revenue component of the rider of $20.6 million over a 24-month period effective for bills rendered on and after the first billing cycle in May 2013. ORS also recommended that SCE&G defer a portion of net lost revenue component in a regulatory asset and recover those amounts over a 12-month period effective for bills rendered on and after the first billing cycle in May 2014. SCE&G agreed with ORS's recommendations. On April 30, 2013, the SCPSC approved SCE&G's request to update its DSM Programs rider, as modified by the agreement between ORS and SCE&G, effective for bills rendered on and after the first billing cycle of May 2013.

SCE&G's initial authorization to operate its DSM Programs expires November 30, 2013. On May 31, 2013, SCE&G filed a request with the SCPSC for approval to extend the operation of its portfolio of DSM Programs. SCE&G also requested approval to continue the use of an annual rate rider which (i) maintains the same terms and conditions currently in effect for the recovery of costs associated with the proposed DSM Programs, the net lost revenue associated with its DSM Programs, and an appropriate incentive for investing in such programs and (ii) modifies the opt-out requirements for industrial customers. SCE&G requested that the proposed DSM Programs rider be effective December 1, 2013.

Electric – BLRA

In November 2012, the SCPSC approved an updated construction schedule and additional updated capital costs of $278 million (SCE&G's portion in 2007 dollars). The November 2012 order approved additional identifiable capital costs of approximately $1 million (SCE&G's portion in 2007 dollars) related to new federal healthcare laws, information security measures, and certain minor design modifications; approximately $8 million (SCE&G's portion in 2007 dollars) related to transmission infrastructure; and approximately $132 million (SCE&G's portion in 2007 dollars) related to additional labor for the oversight of the New Units during construction and for preparing to operate the New Units, and facilities and information technology systems required to support the New Units and their personnel. In addition, the order approved revised substantial completion dates for the New Units based on the March 30, 2012 issuance of the COL and the amounts agreed upon by SCE&G and the Consortium in July 2012 to resolve claims for costs related to COL delays, design modifications of the shield building and certain pre-fabricated structural modules for the New Units and unanticipated rock conditions at the site. Thereafter, two parties filed separate petitions requesting that the SCPSC reconsider its November 2012 order. On December 12, 2012, the SCPSC denied both petitions. In March 2013, both parties appealed the SCPSC's order to the South Carolina Supreme Court. SCE&G is unable to predict the outcome of these appeals.

Under the BLRA, SCE&G is allowed to file revised rates with the SCPSC each year to incorporate the financing cost of any incremental construction work in progress incurred for new nuclear generation. Requested rate adjustments are based on SCE&G’s updated cost of debt and capital structure and on an allowed return on common equity of 11.0%. The SCPSC has approved the following rate changes under the BLRA effective for bills rendered on and after October 30 in the years indicated:

Year	Action		Amount
2012	2.3	% Increase	$52.1 million
2011	2.4	% Increase	$52.8 million

On May 31, 2013, SCE&G filed its annual request for approval of revised rates under the BLRA. On July 30, 2013, ORS filed a report of its review of SCE&G's request. ORS proposes that SCE&G be allowed to increase its rates in the amount of $67.2 million, or 2.87%. If approved, the revised rates will be effective for bills rendered on and after October 30, 2013.

Gas

SCE&G

The RSA is designed to reduce the volatility of costs charged to customers by allowing for more timely recovery of the costs that regulated utilities incur related to natural gas infrastructure. The SCPSC has approved the following rate changes pursuant to annual RSA filings effective with the first billing cycle of November in the years indicated:

Year	Action		Amount
2012	2.1	% Increase	$7.5 million
2011	2.1	% Increase	$8.6 million

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On June 5, 2013, SCE&G submitted its annual RSA filing with the SCPSC for the 12-month period ending March 31, 2013. SCE&G earned a return on its gas distribution operations, after proforma adjustments, that is within the range of its allowable rate of return on common equity. Therefore, SCE&G did not request any adjustments to its rates.

SCE&G's natural gas tariffs include a PGA clause that provides for the recovery of actual gas costs incurred. SCE&G's gas rates are calculated using a methodology which may adjust the cost of gas monthly based on a 12-month rolling average. The annual PGA hearing to review SCE&G's gas purchasing policies and procedures was held in November 2012 before the SCPSC. The SCPSC issued an order in December 2012 finding that SCE&G's gas purchasing policies and practices during the review period of August 1, 2011 through July 31, 2012, were reasonable and prudent. The next annual PGA hearing is scheduled for November 7, 2013.

PSNC Energy

PSNC Energy is subject to a Rider D rate mechanism which allows it to recover from customers all prudently incurred gas costs and certain uncollectible expenses related to gas cost. The Rider D rate mechanism also allows PSNC Energy to recover, in any manner authorized by the NCUC, losses on negotiated gas and transportation sales.

PSNC Energy’s rates are established using a benchmark cost of gas approved by the NCUC, which may be periodically adjusted to reflect changes in the market price of natural gas. PSNC Energy revises its tariffs with the NCUC as necessary to track these changes and accounts for any over- or under-collection of the delivered cost of gas in its deferred accounts for subsequent rate consideration. The NCUC reviews PSNC Energy’s gas purchasing practices annually. In addition, PSNC Energy utilizes a CUT which allows it to adjust its base rates semi-annually for residential and commercial customers based on average per customer consumption.

In October 2012, in connection with PSNC Energy's 2012 Annual Prudence Review, the NCUC determined that PSNC Energy's gas costs, including all hedging transactions, were reasonable and prudently incurred during the 12 months ended March 31, 2012.

Regulatory Assets and Regulatory Liabilities

The Company’s cost-based, rate-regulated utilities recognize in their financial statements certain revenues and expenses in different time periods than do enterprises that are not rate-regulated. As a result, the Company has recorded regulatory assets and regulatory liabilities which are summarized in the following tables. Substantially all regulatory assets are either explicitly excluded from rate base or are effectively excluded from rate base due to their being offset by related liabilities.

Millions of dollars	June 30, 2013	December 31, 2012
Regulatory Assets:		
Accumulated deferred income taxes	$253	$254
Under-collections - electric fuel adjustment clause	71	66
Environmental remediation costs	42	44
AROs and related funding	328	319
Franchise agreements	33	36
Deferred employee benefit plan costs	445	460
Planned major maintenance	—	6
Deferred losses on interest rate derivatives	128	151
Deferred pollution control costs	38	38
Unrecovered plant	19	20
Other	82	70

Total Regulatory Assets	$1,439	$1,464

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Regulatory Liabilities:		
Accumulated deferred income taxes	$20	$21
Asset removal costs	709	692
Storm damage reserve	27	27
Monetization of bankruptcy claim	30	32
Deferred gains on interest rate derivatives	185	110
Planned major maintenance	4	—
Other	1	—
Total Regulatory Liabilities	$976	$882

Accumulated deferred income tax liabilities that arose from utility operations that have not been included in customer rates are recorded as a regulatory asset. Substantially all of these regulatory assets relate to depreciation and are expected to be recovered over the remaining lives of the related property which may range up to approximately 70 years. Similarly, accumulated deferred income tax assets arising from deferred investment tax credits are recorded as a regulatory liability.

Under-collections - electric fuel adjustment clause represent amounts due from customers pursuant to the fuel adjustment clause as approved by the SCPSC during annual hearings which are not expected to be recovered in retail electric rates within 12 months.

Environmental remediation costs represent costs associated with the assessment and clean-up of MGP sites currently or formerly owned by the Company. These regulatory assets are expected to be recovered over periods of up to approximately 27 years.

ARO and related funding represents the regulatory asset associated with the legal obligation to decommission and dismantle Summer Station and conditional AROs. These regulatory assets are expected to be recovered over the related property lives and periods of decommissioning which may range up to approximately 90 years.

Franchise agreements represent costs associated with electric and gas franchise agreements with the cities of Charleston and Columbia, South Carolina. Based on an SCPSC order, SCE&G began amortizing these amounts through cost of service rates in February 2003 over approximately 20 years.

Employee benefit plan costs of the regulated utilities have historically been recovered as they have been recorded under generally accepted accounting principles. Deferred employee benefit plan costs represent amounts of pension and other postretirement benefit costs which were accrued as liabilities and treated as regulatory assets pursuant to FERC guidance, and costs deferred pursuant to specific SCPSC regulatory orders. In connection with the December 2012 rate order, approximately $63 million of deferred pension costs for electric operations are to be recovered through utility rates over approximately 30 years. The remainder of the deferred benefit costs are expected to be recovered through utility rates, primarily over average service periods of participating employees, or up to approximately 12 years.

Planned major maintenance related to certain fossil fueled turbine/generation equipment and nuclear refueling outages is accrued in periods other than when incurred, as approved pursuant to specific SCPSC orders. SCE&G collects $18.4 million annually for fossil fueled turbine/generation equipment maintenance. Through December 31, 2012, nuclear refueling charges were accrued during each 18-month refueling outage cycle as a component of cost of service. In connection with the December 2012 rate order, effective January 1, 2013, SCE&G began to collect and accrue $17.2 million annually for nuclear-related refueling charges.

Deferred losses or gains on interest rate derivatives represent the effective portions of changes in fair value and payments made or received upon termination of certain interest rate derivatives designated as cash flow hedges. These amounts are expected to be amortized to interest expense over the lives of the underlying debt, up to approximately 30 years.

Deferred pollution control costs represent deferred depreciation and operating and maintenance costs associated with the scrubbers installed at Wateree and Williams Stations pursuant to specific regulatory orders. Such costs are being recovered through utility rates over periods up to 30 years.

Unrecovered plant represents the net book value of a coal-fired generating unit retired from service prior to being fully depreciated. Pursuant to the December 2012 rate order, SCE&G is amortizing these amounts over the unit's original remaining useful life of approximately 14 years. Unamortized amounts are included in rate base.

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Various other regulatory assets are expected to be recovered in rates over periods of up to approximately 30 years.

Asset removal costs represent estimated net collections through depreciation rates of amounts to be incurred for the removal of assets in the future.

The storm damage reserve represents an SCPSC-approved collection through SCE&G electric rates, capped at $100 million, which can be applied to offset incremental storm damage costs in excess of $2.5 million in a calendar year. Pursuant to specific regulatory orders, SCE&G has suspended storm damage reserve collection through rates indefinitely.

The monetization of bankruptcy claim represents proceeds from the sale of a bankruptcy claim which are being amortized into operating revenue through February 2024.

The SCPSC, the NCUC or the FERC has reviewed and approved through specific orders most of the items shown as regulatory assets. Other regulatory assets include, but are not limited to, certain costs which have not been approved for recovery by the SCPSC, the NCUC or by the FERC. In recording such costs as regulatory assets, management believes the costs will be allowable under existing rate-making concepts that are embodied in rate orders received by the Company. The costs are currently not being recovered, but are expected to be recovered through rates in future periods. In the future, as a result of deregulation or other changes in the regulatory environment or changes in accounting requirements, the Company could be required to write off its regulatory assets and liabilities. Such an event could have a material effect on the Company's results of operations, liquidity or financial position in the period the write-off would be recorded.

3.COMMON EQUITY

Changes in common equity during the six months ended June 30, 2013 and 2012 were as follows:

Millions of dollars	2013	2012
Balance at January 1,	$4,154	$3,889
Common stock issued	247	50
Dividends declared	(141)	(130)
Comprehensive income	246	201
Balance as of June 30,	$4,506	$4,010

SCANA had 200 million shares of common stock authorized as of June 30, 2013 and December 31, 2012, of which 139.7 million and 132.0 million were issued and outstanding at June 30, 2013 and December 31, 2012, respectively.

On March 5, 2013, SCANA settled all forward sales contracts related to its common stock through the issuance of approximately 6.6 million common shares, resulting in net proceeds of approximately $196.2 million.

Reclassifications of gains (losses) from AOCI into earnings were as follows (amounts are net of taxes):

Millions of dollars	2013	2012	Income Statement Line Item Affected
Three months ended June 30,			
Interest rate contracts	$(1)	$(1)	Increase in interest expense
Commodity contracts	—	(3)	Increase in gas purchased for resale
Amortization of deferred employee benefit plan costs	(1)	(1)	
Total reclassifications	$(2)	$(5)	

Six months ended June 30,			
Interest rate contracts	$(3)	$(3)	Increase in interest expense
Commodity contracts	(2)	(11)	Increase in gas purchased for resale
Amortization of deferred employee benefit plan costs	(1)	(1)	
Total reclassifications	$(6)	$(15)	

Reclassifications of the amortization of deferred employee benefit costs were not significant for any period presented.

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4. LONG-TERM DEBT AND LIQUIDITY

Long-term Debt

In June 2013, SCE&G issued $400 million of 4.60% first mortgage bonds due June 15, 2043. Proceeds from this sale were used to pay at maturity $150 million of its 7.125% first mortgage bonds due June 15, 2013, to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures, and for general corporate purposes.

In January 2013, JEDA issued at a premium, for the benefit of SCE&G, $39.5 million of 4.0% tax-exempt industrial revenue bonds due February 1, 2028, and $14.7 million of 3.63% tax-exempt industrial revenue bonds due February 1, 2033. Proceeds from these sales were loaned by JEDA to SCE&G and, together with other available funds, were used to redeem prior to maturity $56.9 million of 5.2% industrial revenue bonds due November 1, 2027.

Substantially all of SCE&G's and GENCO's electric utility plant is pledged as collateral in connection with long-term debt. The Company is in compliance with all debt covenants.

Liquidity

SCANA, SCE&G (including Fuel Company) and PSNC Energy had available the following committed LOC, and had outstanding the following LOC advances, commercial paper, and LOC-supported letter of credit obligations:

	SCANA		SCE&G		PSNC Energy	
Millions of dollars	June 30, 2013	December 31, 2012	June 30, 2013	December 31, 2012	June 30, 2013	December 31, 2012
Lines of credit:						
Total committed long-term	$300	$300	$1,400	$1,400	$100	$100
LOC advances	—	—	—	—	—	—
Weighted average interest rate	—	—	—	—	—	—
Outstanding commercial paper (270 or fewer days)	$65	$142	$238	$449	—	$32
Weighted average interest rate	0.48 %	0.58 %	0.30 %	0.42 %	—	0.44 %
Letters of credit supported by LOC	$3	$3	$0.3	$0.3	—	—
Available	$232	$155	$1,162	$951	$100	$68

SCANA, SCE&G (including Fuel Company) and PSNC Energy are parties to five-year credit agreements in the amounts of $300 million, $1.2 billion (of which $500 million relates to Fuel Company) and $100 million, respectively, which expire in October 2017. In addition, SCE&G is party to a three-year credit agreement in the amount of $200 million which expires in October 2015. These credit agreements are used for general corporate purposes, including liquidity support for each company's commercial paper program and working capital needs and, in the case of Fuel Company, to finance or refinance the purchase of nuclear fuel, certain fossil fuels, and emission and other environmental allowances. These committed long-term facilities are revolving lines of credit under credit agreements with a syndicate of banks. Wells Fargo Bank, National Association, Bank of America, N.A. and Morgan Stanley Bank, N.A. each provide 10.7% of the aggregate $1.8 billion credit facilities, JPMorgan Chase Bank, N.A., Mizuho Corporate Bank, Ltd., TD Bank N.A., Credit Suisse AG, Cayman Island Branch and UBS Loan Finance LLC each provide 8.9%, and Branch Banking and Trust Company, Union Bank, N.A. and U.S. Bank National Association each

provide 6.3%. Two other banks provide the remaining support. The Company pays fees to the banks as compensation for maintaining the committed lines of credit. Such fees were not material in any period presented.
The Company is obligated with respect to an aggregate of $67.8 million of industrial revenue bonds which are secured by letters of credit issued by Branch Banking and Trust Company. The letters of credit expire, subject to renewal, in the fourth quarter of 2014.

5.INCOME TAXES

No material changes in the status of the Company's tax positions have occurred through June 30, 2013.

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6.DERIVATIVE FINANCIAL INSTRUMENTS

The Company recognizes all derivative instruments as either assets or liabilities in the statement of financial position and measures those instruments at fair value. The Company recognizes changes in the fair value of derivative instruments either in earnings, as a component of other comprehensive income (loss) or, for regulated subsidiaries, within regulatory assets
or regulatory liabilities, depending upon the intended use of the derivative and the resulting designation.

Policies and procedures and risk limits are established to control the level of market, credit, liquidity and operational and administrative risks assumed by the Company. SCANA's Board of Directors has delegated to a Risk Management Committee the authority to set risk limits, establish policies and procedures for risk management and measurement, and oversee and review the risk management process and infrastructure for SCANA and each of its subsidiaries. The Risk Management Committee, which is comprised of certain officers, including the Company's Risk Management Officer and senior officers, apprises the Audit Committee of the Board of Directors with regard to the management of risk and brings to the Audit Committee's attention significant areas of concern. Written policies define the physical and financial transactions that are approved, as well as the authorization requirements and limits for transactions.

Commodity Derivatives

The Company uses derivative instruments to hedge forward purchases and sales of natural gas, which create market risks of different types. Instruments designated as cash flow hedges are used to hedge risks associated with fixed price obligations in a volatile market and risks associated with price differentials at different delivery locations. Instruments designated as fair value hedges are used to mitigate exposure to fluctuating market prices created by fixed prices of stored natural gas. The basic types of financial instruments utilized are exchange-traded instruments, such as NYMEX futures contracts or options, and over-the-counter instruments such as options and swaps, which are typically offered by energy companies and financial institutions. Cash settlements of commodity derivatives are classified as operating activities in the condensed consolidated statements of cash flows.

PSNC Energy hedges natural gas purchasing activities using over-the-counter options and NYMEX futures and options. PSNC Energy's tariffs also include a provision for the recovery of actual gas costs incurred, including any costs of hedging. PSNC Energy records premiums, transaction fees, margin requirements and any realized gains or losses from its hedging program in deferred accounts as a regulatory asset or liability for the under- or over-recovery of gas costs. These derivative financial instruments are not designated as hedges for accounting purposes.

The unrealized gains and losses on qualifying cash flow hedges of nonregulated operations are deferred in OCI. When the hedged transactions affect earnings, the previously recorded gains and losses are reclassified from AOCI to cost of gas. The effects of gains or losses resulting from these hedging activities are either offset by the recording of the related hedged transactions or are included in gas sales pricing decisions made by the business unit.

As an accommodation to certain customers, SEMI, as part of its energy management services, offers fixed price supply contracts which are accounted for as derivatives. These sales contracts are offset by the purchase of supply futures and swaps which are also accounted for as derivatives. Neither the sales contracts nor the related supply futures and swaps are designated as hedges for accounting purposes.

Interest Rate Swaps

The Company may use interest rate swaps to manage interest rate risk and exposure to changes in fair value attributable to changes in interest rates on certain debt issuances. These swaps may be designated as either fair value hedges or cash flow hedges.

The Company synthetically converts variable rate debt to fixed rate debt using swaps that are designated as cash flow hedges. Periodic payments to or receipts from swap counterparties related to these derivatives are recorded within interest expense.

In anticipation of the issuance of debt, the Company may use treasury rate lock or forward starting swap agreements that are designated as cash flow hedges. The effective portions of changes in fair value and payments made or received upon termination of such agreements for regulated subsidiaries are recorded in regulatory assets or regulatory liabilities, and for the holding company or nonregulated subsidiaries, are recorded in OCI. Such amounts are amortized to interest expense over the

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term of the underlying debt. Ineffective portions are recognized in income. Cash payments made or received upon termination of these financial instruments are classified as investing activities for cash flow statement purposes.

Quantitative Disclosures Related to Derivatives

The Company was party to natural gas derivative contracts outstanding in the following quantities:

	Commodity and Other Energy Management Contracts (in MMBTU)			
Hedge designation	Gas Distribution	Retail Gas Marketing	Energy Marketing	Total
As of June 30, 2013				
Cash flow	—	6,924,000	16,162,250	23,086,250
Not designated (a)	6,680,000	200,000	15,206,863	22,086,863
Total (a)	6,680,000	7,124,000	31,369,113	45,173,113
As of December 31, 2012				
Cash flow	—	6,490,000	18,937,000	25,427,000
Not designated (b)	5,170,000	—	17,703,275	22,873,275
Total (b)	5,170,000	6,490,000	36,640,275	48,300,275

(a) Includes an aggregate 1,365,752 MMBTU related to basis swap contracts in Energy Marketing.
(b) Includes an aggregate 3,500,000 MMBTU related to basis swap contracts in Energy Marketing.

The Company was not party to any interest rate swap designated as a fair value hedge during any period presented. The Company was party to interest rate swaps designated as cash flow hedges with aggregate notional amounts of $663.8 million at June 30, 2013 and $1.1 billion at December 31, 2012.

The fair value of energy-related derivatives and interest rate derivatives was reflected in the condensed consolidated balance sheet as follows:

	Fair Values of Derivative Instruments			
	Asset Derivatives		Liability Derivatives	
Millions of dollars	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
As of June 30, 2013				
Derivatives designated as hedging instruments				
Interest rate	Prepayments and other	$72	Other current liabilities	$6
	Other deferred debits and other assets	34	Other deferred credits and other liabilities	21
Commodity			Prepayments and other	1
			Other current liabilities	3
Total		$106		$31
Derivatives not designated as hedging instruments				
Commodity	Prepayments and other	$1		
Energy management	Prepayments and other	5	Other current liabilities	$5
	Other deferred debits and other assets	5	Other deferred credits and other liabilities	5
Total		$11		$10

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As of December 31, 2012				
Derivatives designated as hedging instruments				
Interest rate	Prepayments and other	$42	Other current liabilities	$70
	Other deferred debits and other assets	31	Other deferred credits and other liabilities	36
Commodity	Prepayments and other	1	Other current liabilities	4
Total		$74		$110
Derivatives not designated as hedging instruments				
Commodity	Prepayments and other	$1		
Energy management	Prepayments and other	7	Prepayments and other	$1
	Other deferred debits and other assets	6	Other current liabilities	6
			Other deferred debits and other assets	6
Total		$14		$13

The effect of derivative instruments on the condensed consolidated statements of income is as follows:

Fair Value Hedges

With regard to the Company's interest rate swaps designated as fair value hedges, any gains or losses related to the swaps or the fixed rate debt are recognized in current earnings and included in interest expense. The Company had no interest rate swaps designated as fair value hedges for any period presented, and the amortization of deferred gains on previously terminated swaps were not significant during any period presented.

Cash Flow Hedges

Derivatives in Cash Flow Hedging Relationships

	Gain (Loss) Deferred in Regulatory Accounts (Effective Portion)			Loss Reclassified from Deferred Accounts into Income (Effective Portion)	
Millions of dollars	2013	2012	Location	2013	2012
Three Months Ended June 30,					
Interest rate	$61	$(2)	Interest expense	—	—
Six Months Ended June 30,					
Interest rate	$96	$28	Interest expense	$(1)	$(1)

	Gain (Loss) Recognized in OCI, net of tax (Effective Portion)			Loss Reclassified from AOCI into Income, net of tax (Effective Portion)	
Millions of dollars	2013	2012	Location	2013	2012
Three Months Ended June 30,					
Interest rate	$3	$(4)	Interest expense	$(1)	$(1)
Commodity	(3)	1	Gas purchased for resale	—	(3)
Total	—	$(3)		$(1)	$(4)
Six Months Ended June 30,					

Interest rate	$4	$(4)	Interest expense	$(3)	$(3)
Commodity	(1)	(3)	Gas purchased for resale	(2)	(11)
Total	$3	$(7)		$(5)	$(14)

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As of June 30, 2013, the Company expects that during the next 12 months reclassifications from accumulated other comprehensive income (loss) to earnings arising from cash flow hedges will include approximately $2.0 million as an increase to gas cost and approximately $7.0 million as an increase to interest expense, assuming natural gas and financial markets remain at their current levels. As of June 30, 2013, all of the Company's commodity cash flow hedges settle by their terms before the end of 2015.

Derivatives not designated as Hedging Instruments		Loss Recognized in Income	
Millions of dollars	Location	2013	2012
Three Months Ended June 30,			
Commodity	Gas purchased for resale	—	—
Six Months Ended June 30,			
Commodity	Gas purchased for resale	—	$(1)

Hedge Ineffectiveness

Other losses recognized in income representing ineffectiveness on interest rate hedges designated as cash flow hedges were insignificant in each of the three and six months ended June 30, 2013 and 2012, respectively.

Credit Risk Considerations

The Company limits credit risk in its commodity and interest rate derivatives activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. In this regard, the Company uses credit ratings provided by credit rating agencies and current market-based qualitative and quantitative data, as well as financial statements, to assess the financial health of counterparties on an ongoing basis. The Company uses standardized master agreements which may include collateral requirements. These master agreements permit the netting of cash flows associated with a single counterparty. Cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. The collateral agreements permit the secured party to demand the posting of cash or letters of credit in the event an exposure exceeds the established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with the Company's credit policies and due diligence. In addition, collateral agreements allow for the termination and liquidation of all positions in the event of a failure or inability to post collateral.

Certain of the Company's derivative instruments contain contingent provisions that may require the Company to provide collateral upon the occurrence of specific events, primarily credit downgrades. As of June 30, 2013 and December 31, 2012, the Company has posted $36.1 million and $78.3 million, respectively, of collateral related to derivatives with contingent provisions that were in a net liability position. Collateral related to the positions expected to close in the next 12 months is recorded in Prepayments and other on the consolidated balance sheets. Collateral related to the noncurrent positions is recorded in Other within Deferred Debits and Other Assets on the consolidated balance sheets. If all of the contingent features underlying these instruments had been fully triggered as of June 30, 2013 and December 31, 2012, the Company could have been required to post an additional $3.2 million and $26.2 million, respectively, of collateral with its counterparties. The aggregate fair value of all derivative instruments with contingent provisions that are in a net liability position as of June 30, 2013 and December 31, 2012 is $39.3 million and $104.5 million, respectively.

In addition, as of June 30, 2013 and December 31, 2012, the Company has collected no cash collateral related to interest rate derivatives with contingent provisions that are in a net asset position. If all the contingent features underlying these instruments were fully triggered as of June 30, 2013 and December 31, 2012, the Company could request $67.7 million and $32.1 million, respectively, of cash collateral from its counterparties. The aggregate fair value of all derivative instruments with contingent provisions that are in a net asset position as of June 30, 2013 and December 31, 2012 is $67.7 million and $32.1 million, respectively. In addition, at June 30, 2013, the Company could have called on letters of credit in the amount of $10 million related to $10 million in commodity derivatives that are in a net asset position, compared to letters of credit of $10 million related to derivatives of $13 million at December 31, 2012, if all the contingent features underlying these instruments had been fully triggered.

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Information related to the Company's offsetting of derivative assets follows:

Millions of dollars	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Statement of Financial Position	Net Amounts Presented in the Statement of Financial Position	Gross Amounts Not Offset in the Statement of Financial Position		
				Financial Instruments	Cash Collateral Received	Net Amount
As of June 30, 2013						
Interest rate	$106	—	$106	$(5)	—	$101
Commodity	1	—	1	—	—	1
Energy management	10	—	10	—	—	10
Total	$117	—	$117	$(5)	—	$112
Balance sheet location	Prepayments and other		$78			
	Other deferred debits and other assets		39			
	Total		$117			
As of December 31, 2012						
Interest rate	$73	—	$73	$(17)	—	$56
Commodity	2	—	2	—	—	2
Energy management	13	$(1)	12	—	—	12
Total	$88	$(1)	$87	$(17)	—	$70
Balance sheet location	Prepayments and other		$50			
	Other deferred debits and other assets		37			
	Total		$87			

Information related to the Company's offsetting of derivative liabilities follows:

Millions of dollars	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Statement of Financial Position	Net Amounts Presented in the Statement of Financial Position	Gross Amounts Not Offset in the Statement of Financial Position		
				Financial Instruments	Cash Collateral Posted	Net Amount
As of June 30, 2013						
Interest rate	$27	—	$27	$(5)	$(22)	—
Commodity	4	—	4	—	—	$4
Energy management	11	$(1)	10	—	(9)	1
	$42	$(1)	$41	$(5)	$(31)	$5
Balance sheet location	Prepayments and other		$1			
	Other current liabilities		14			
	Other deferred credits and other liabilities		26			

Total	$41

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As of December 31, 2012						
Interest rate	$106	—	$106	$(17)	$(67)	$22
Commodity	4	—	4	—	—	4
Energy management	13	$(1)	12	—	(11)	1
	$123	$(1)	$122	$(17)	$(78)	$27

Balance sheet location	Other current liabilities	$80
	Other deferred credits and other liabilities	42
	Total	$122

7. FAIR VALUE MEASUREMENTS, INCLUDING DERIVATIVES

The Company values available for sale securities using quoted prices from a national stock exchange, such as the NASDAQ, where the securities are actively traded. For commodity derivative and energy management assets and liabilities, the Company uses unadjusted NYMEX prices to determine fair value, and considers such measures of fair value to be Level 1 for exchange traded instruments and Level 2 for over-the-counter instruments. The Company's interest rate swap agreements are valued using discounted cash flow models with independently sourced market data. Fair value measurements, and the level within the fair value hierarchy in which the measurements fall, were as follows:

		Fair Value Measurements Using	
Millions of dollars		Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)
As of June 30, 2013			
Assets -	Available for sale securities	$9	—
	Interest rate contracts	—	$106
	Commodity contracts	1	—
	Energy management contracts	—	10
Liabilities -	Interest rate contracts	—	27
	Commodity contracts	—	4
	Energy management contracts	—	13
As of December 31, 2012			
Assets -	Available for sale securities	$6	—
	Interest rate contracts	—	$73
	Commodity contracts	1	1
	Energy management contracts	—	13
Liabilities -	Interest rate contracts	—	106
	Commodity contracts	—	4
	Energy management contracts	1	15

There were no fair value measurements based on significant unobservable inputs (Level 3) for either period presented. In addition, there were no transfers of fair value amounts into or out of Levels 1, 2 or 3 during the periods presented.

Financial instruments for which the carrying amount may not equal estimated fair value at June 30, 2013 and December 31, 2012 were as follows:

June 30, 2013	December 31, 2012

Millions of dollars	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Long-term debt	$5,454.6	$5,961.3	$5,121.0	$6,115.0

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Fair values of long-term debt instruments are based on net present value calculations using independently sourced market data that incorporate a developed discount rate using similarly rated long-term debt, along with benchmark interest rates. As such, the aggregate fair values presented above are considered to be Level 2. Early settlement of long-term debt may not be possible or may not be considered prudent.

Carrying values of short-term borrowings approximate fair value, and are based on quoted prices from dealers in the commercial paper market. The resulting fair value is considered to be Level 2.

8. EMPLOYEE BENEFIT PLANS

Pension and Other Postretirement Benefit Plans

Components of net periodic benefit cost recorded by the Company were as follows:

	Pension Benefits		Other Postretirement Benefits	
Millions of dollars	2013	2012	2013	2012
Three months ended June 30,				
Service cost	$5.9	$4.9	$1.6	$1.2
Interest cost	9.4	10.6	2.7	3.0
Expected return on assets	(15.3)	(14.8)	—	—
Prior service cost amortization	1.7	1.8	0.2	0.3
Transition obligation amortization	—	—	0.1	0.1
Amortization of actuarial losses	5.5	4.6	0.9	0.2
Net periodic benefit cost	$7.2	$7.1	$5.5	$4.8
Six months ended June 30,				
Service cost	$11.8	$9.7	$3.2	$2.5
Interest cost	18.9	21.3	5.5	6.0
Expected return on assets	(30.7)	(29.6)	—	—
Prior service cost amortization	3.4	3.5	0.4	0.5
Transition obligation amortization	—	—	0.3	0.3
Amortization of actuarial losses	10.9	9.3	1.7	0.4
Net periodic benefit cost	$14.3	$14.2	$11.1	$9.7

No contribution to the pension trust will be necessary until after 2014, nor will limitations on benefit payments apply. As authorized by the SCPSC, prior to January 1, 2013 SCE&G deferred all pension expense related to retail electric and gas operations as a regulatory asset. In connection with the SCPSC's December 2012 rate order, effective January 1, 2013 SCE&G began recovering pension expense related to retail electric operations through a rate rider that is adjusted annually. SCE&G continues to defer such costs related to gas operations. Costs totaling $0.6 million and $1.2 million related to gas operations were deferred for the three and six months ended June 30, 2013, respectively. Costs totaling $3.7 million and $7.4 million related to electric and gas operations were deferred for the corresponding periods in 2012. Previously deferred costs related to electric operations are being recovered as described in Note 2.

9. COMMITMENTS AND CONTINGENCIES

Nuclear Insurance

Under Price-Anderson, SCE&G (for itself and on behalf of Santee Cooper, a one-third owner of Summer Station Unit 1) maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at the Company's nuclear power plant. Price-Anderson provides funds up to $12.6 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $375 million by ANI with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. Each reactor licensee is currently liable for up to $117.5 million per reactor owned for each nuclear incident occurring at any reactor in the United States, provided that not more than $17.5 million of the liability per reactor would be assessed per year. SCE&G's maximum assessment, based on its two-thirds ownership of Summer Station Unit 1, would be $78.3 million per incident, but not more

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than $11.7 million per year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years.

SCE&G currently maintains insurance policies (for itself and on behalf of Santee Cooper) with NEIL. The policies provide coverage to Summer Station Unit 1 for property damage and outage costs up to $2.75 billion. In addition, a builder's risk insurance policy has been purchased from NEIL for the construction of the New Units. This policy provides the owners of the New Units up to $500 million in limits of accidental property damage occurring during construction. The NEIL policies, in the aggregate, are subject to a maximum loss of $2.75 billion for any single loss occurrence. All of the NEIL policies permit retrospective assessments under certain conditions to cover insurer’s losses. Based on the current annual premium, SCE&G’s portion of the retrospective premium assessment would not exceed $40.6 million.

To the extent that insurable claims for property damage, decontamination, repair and replacement and other costs and expenses arising from a nuclear incident at Summer Station Unit 1 exceed the policy limits of insurance, or to the extent such insurance becomes unavailable in the future, and to the extent that SCE&G's rates would not recover the cost of any purchased replacement power or other costs and expenses, SCE&G will retain the risk of loss as a self-insurer. SCE&G has no reason to anticipate a serious nuclear incident. However, if such an incident were to occur, it likely would have a material impact on the Company’s results of operations, cash flows and financial position.

Environmental

On April 13, 2012, the EPA issued a proposed rule to establish NSPS for GHG emissions from fossil fuel-fired electric generating units. If finalized as proposed, this rule would establish performance standards for new and modified generating units, along with emissions guidelines for existing generating units. This rule would amend the NSPS for electric generating units and establish the first NSPS for GHG emissions. Essentially, the rule would require all new fossil fuel-fired power plants to meet the carbon dioxide emissions profile of a combined cycle natural gas plant. While most new natural gas plants will not be required to include any new technologies, no new coal plants could be constructed without carbon capture and sequestration capabilities. As part of the President's Climate Action Plan and by Presidential Memorandum issued June 25, 2013, the EPA was directed to issue a revised carbon standard for new power plants by September 20, 2013, to be made final as soon as appropriate. Standards, regulations, or guidelines are also required for existing units by June 1, 2014, to be made final no later than June 1, 2015. The Company is evaluating the proposed rule, but cannot predict when the rule will become final, if at all, or what conditions it may impose on the Company, if any. The Company expects that any costs incurred to comply with GHG emission requirements will be recoverable through rates.

In 2005, the EPA issued the CAIR, which required the District of Columbia and 28 states, including South Carolina, to reduce nitrogen oxide and sulfur dioxide emissions in order to attain mandated state levels. CAIR set emission limits to be met in two phases beginning in 2009 and 2015, respectively, for nitrogen oxide and beginning in 2010 and 2015, respectively, for sulfur dioxide. SCE&G and GENCO determined that additional air quality controls would be needed to meet the CAIR requirements. On July 6, 2011 the EPA issued the CSAPR. This rule replaced CAIR and the Clean Air Transport Rule proposed in July 2010 and is aimed at addressing power plant emissions that may contribute to air pollution in other states. CSAPR requires states in the eastern United States to reduce power plant emissions, specifically sulfur dioxide and nitrogen oxide. On December 30, 2011, the United States Court of Appeals for the District of Columbia issued an order staying CSAPR and reinstating CAIR pending resolution of an appeal of CSAPR. On August 21, 2012, the Court of Appeals vacated CSAPR and left CAIR in place. The EPA's petition for rehearing of the Court of Appeals' order has been denied. On March 29, 2013, the U.S. Solicitor General petitioned the U.S. Supreme Court to review the D.C. Circuit Court's decision on CSAPR. On June 24, 2013, the U.S. Supreme Court agreed to review the lower court's decision. Air quality control installations that SCE&G and GENCO have already completed have allowed the Company to comply with the reinstated CAIR. The Company will continue to pursue strategies to comply with all applicable environmental regulations. Any costs incurred to comply with such regulations are expected to be recoverable through rates.

In April 2012, the EPA's rule containing new standards for mercury and other specified air pollutants became effective. The rule provides up to four years for facilities to meet the standards, and the Company's evaluation of the rule is ongoing. The Company's decision in 2012 to retire certain coal-fired units or convert them to burn natural gas and its project to build the New Units (see Note 1) along with other actions are expected to result in the Company's compliance with the EPA's rule. Any costs incurred to comply with this rule or other rules issued by the EPA in the future are expected to be recoverable through rates.

The EPA is conducting an enforcement initiative against the utilities industry related to the NSR provisions and the NSPS of the CAA. As part of the initiative, many utilities have received requests for information under Section 114 of the CAA. In addition, the DOJ, on behalf of the EPA, has taken civil enforcement action against several utilities. The primary basis for these actions is the assertion by the EPA that maintenance activities undertaken by the utilities at their coal-fired power

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plants constituted “major modifications” which required the installation of costly BACT. Some of the utilities subject to the actions have reached settlement. Though the Company cannot predict what action, if any, the EPA will initiate against it, any costs incurred are expected to be recoverable through rates.

The Company maintains an environmental assessment program to identify and evaluate its current and former operations sites that could require environmental clean-up. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. Environmental liabilities are accrued when the criteria for loss contingencies are met. These estimates are refined as additional information becomes available; therefore, actual expenditures could differ significantly from the original estimates. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Amounts expected to be recovered through rates are recorded in regulatory assets and, if applicable, amortized over approved amortization periods. Other environmental costs are recorded to expense.

SCE&G is responsible for four decommissioned MGP sites in South Carolina which contain residues of byproduct chemicals. These sites are in various stages of investigation, remediation and monitoring under work plans approved by DHEC and the EPA. SCE&G anticipates that major remediation activities at all these sites will continue until 2016 and will cost an additional $21.9 million, which is accrued in Other within Deferred Credits and Other Liabilities on the condensed consolidated balance sheet. SCE&G expects to recover any cost arising from the remediation of MGP sites through rates. At June 30, 2013, deferred amounts, net of amounts previously recovered through rates and insurance settlements, totaled $37.9 million and are included in regulatory assets.

PSNC Energy is responsible for environmental clean-up at five sites in North Carolina on which MGP residuals are present or suspected. PSNC Energy’s actual remediation costs for these sites will depend on a number of factors, such as actual site conditions, third-party claims and recoveries from other PRPs. PSNC Energy has recorded a liability and associated regulatory asset of approximately $3.0 million, the estimated remaining liability at June 30, 2013. PSNC Energy expects to recover through rates any cost allocable to PSNC Energy arising from the remediation of these sites.

New Nuclear Construction

SCE&G, on behalf of itself and as agent for Santee Cooper, has contracted with the Consortium for the design and construction of the New Units at the site of Summer Station. SCE&G's share of the estimated cash outlays (future value, excluding AFC) totals approximately $5.5 billion for plant and related transmission infrastructure costs, and is projected based on historical one-year and five-year escalation rates as required by the SCPSC.

The Consortium has experienced delays in the schedule for fabrication and delivery of sub-modules for the New Units. Following an examination of this issue, the Consortium has preliminarily indicated that the substantial completion of the first New Unit is expected to be delayed until late 2017 or the first quarter of 2018 and that the substantial completion of the second New Unit is expected to be similarly delayed. The substantial completion dates currently approved by the SCPSC for the first and second New Units are March 15, 2017 and May 15, 2018, respectively. The SCPSC has also approved an 18-month contingency period beyond each of these dates. The preliminary expected new substantial completion dates are within the contingency periods. SCE&G cannot predict with certainty the extent to which the issue with the sub-modules or the delays in the substantial completion of the New Units will result in increased project costs. However, the preliminary estimate of the delay-related costs associated with SCE&G's share of the New Units is approximately $200 million. SCE&G intends to continue to work with the Consortium to refine this preliminary estimate and expects to have further discussions with the Consortium regarding responsibility for these increased costs.

In addition to the above-described project delays, SCE&G has also become aware of recent press reports concerning financial difficulties at a supplier responsible for certain significant components of the project. SCE&G has asked the Consortium to evaluate the potential for disruptions in such equipment fabrication and possible responses. Any disruptions could impact the project's schedule or costs, and such impacts could be material.

The parties to the EPC Contract have established both informal and formal dispute resolution procedures in order to resolve issues that arise during the course of constructing a project of this magnitude. During the course of activities under the EPC Contract, issues have materialized that impact project budget and schedule. Claims specifically relating to COL delays,
design modifications of the shield building and certain pre-fabricated modules for the New Units and unanticipated rock
conditions at the site resulted in assertions of contractual entitlement to recover additional costs to be incurred. The resolution
of these specific claims is discussed in Note 2. SCE&G expects to resolve any disputes that arise in the future, including any which may arise with respect to the delay-related costs discussed above, through both the informal and formal procedures and

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anticipates that any additional costs that arise through such dispute resolution processes, as well as other costs identified from time to time, will be recoverable through rates.

When the NRC issued the COLs for the New Units, two of the conditions that it imposed were requiring inspection and testing of certain components of the New Units' passive cooling system, and requiring the development of strategies to respond to extreme natural events resulting in the loss of power at the New Units. In addition, the NRC directed the Office of New Reactors to issue to SCE&G an order requiring enhanced, reliable spent fuel pool instrumentation, as well as a request for information related to emergency plant staffing. These conditions and requirements are responsive to the NRC's Near-Term Task Force report titled "Recommendations for Enhancing Reactor Safety in the 21st Century." This report was prepared in the wake of the March 2011 earthquake-generated tsunami, which severely damaged several nuclear generating units and their back-up cooling systems in Japan. SCE&G continues to evaluate the impact of these conditions and requirements that may be imposed on the construction and operation of the New Units, and SCE&G is preparing an integrated response plan for the New Units, which it expects to submit to the NRC in August 2013. SCE&G cannot predict what additional regulatory or other outcomes may be implemented in the United States, or how such initiatives would impact SCE&G's existing Summer Station or the construction or operation of the New Units.

As previously reported, SCE&G has been advised by Santee Cooper that it is reviewing certain aspects of its capital improvement program and long-term power supply plan, including the level of its participation in the New Units. SCE&G is unable to predict whether any change in Santee Cooper's ownership interest or the addition of new joint owners will increase project costs or delay the commercial operation dates of the New Units. Any such project cost increase or delay could be material.

10. SEGMENT OF BUSINESS INFORMATION

The Company's reportable segments are listed in the following table. The Company uses operating income to measure profitability for its regulated operations; therefore, net income is not allocated to the Electric Operations and Gas Distribution segments. The Company uses net income to measure profitability for its Retail Gas Marketing and Energy Marketing segments. Gas Distribution is comprised of the local distribution operations of SCE&G and PSNC Energy which meet the criteria for aggregation. All Other includes equity method investments and other nonreportable segments. Nonreportable segments include a FERC-regulated interstate pipeline company and other companies that conduct nonregulated operations in energy-related and telecommunications industries.

Millions of dollars	External Revenue	Intersegment Revenue	Operating Income	Net Income
Three Months Ended June 30, 2013				
Electric Operations	$610	$2	$178	n/a
Gas Distribution	155	—	7	n/a
Retail Gas Marketing	79	—	—	$(3)
Energy Marketing	169	47	—	1
All Other	7	101	6	(2)
Adjustments/Eliminations	(4)	(150)	(2)	89
Consolidated Total	$1,016	$—	$189	$85
Six Months Ended June 30, 2013				
Electric Operations	$1,193	$4	$331	n/a
Gas Distribution	534	—	100	n/a
Retail Gas Marketing	258	—	—	$19
Energy Marketing	336	89	—	4
All Other	19	208	13	1
Adjustments/Eliminations	(13)	(301)	38	213

Consolidated Total	$2,327	$—	$482	$237

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Three Months Ended June 30, 2012				
Electric Operations	$592	$3	$164	n/a
Gas Distribution	126	—	5	n/a
Retail Gas Marketing	71	—	n/a	$(3)
Energy Marketing	118	23	n/a	2
All Other	10	103	4	(4)
Adjustments/Eliminations	(9)	(129)	(2)	77
Consolidated Total	$908	$—	$171	$72
Six Months Ended June 30, 2012				
Electric Operations	$1,137	$5	$291	n/a
Gas Distribution	400	—	88	n/a
Retail Gas Marketing	224	—	n/a	$8
Energy Marketing	250	49	n/a	4
All Other	21	209	11	1
Adjustments/Eliminations	(17)	(263)	19	180
Consolidated Total	$2,015	$—	$409	$193

Segment Assets	June 30, 2013	December 31, 2012
Electric Operations	$9,272	$8,989
Gas Distribution	2,294	2,292
Retail Gas Marketing	162	153
Energy Marketing	112	122
All Other	1,435	1,415
Adjustments/Eliminations	1,663	1,645
Consolidated Total	$14,938	$14,616

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Item 2. MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

SCANA CORPORATION

The following discussion should be read in conjunction with Management’s Discussion and Analysis of Financial Condition and Results of Operations appearing in SCANA’s Annual Report on Form 10-K for the year ended December 31, 2012.

RESULTS OF OPERATIONS
FOR THE THREE AND SIX MONTHS ENDED JUNE 30, 2013
AS COMPARED TO THE CORRESPONDING PERIODS IN 2012

Earnings Per Share

Earnings per share was as follows:

	Second Quarter		Year to Date	
	2013	2012	2013	2012
Basic earnings per share	$0.60	$0.55	$1.73	$1.48
Diluted earnings per share	$0.60	$0.54	$1.72	$1.46

Second Quarter

Basic earnings per share increased due to higher electric margin from base rate increases. This margin increase was partially offset by higher operation and maintenance expenses, higher depreciation expense, higher property taxes and dilution from additional shares outstanding as further discussed below.

Year to Date

Basic earnings per share increased due to higher electric margin and higher gas margin. These margin increases were partially offset by higher operation and maintenance expenses, higher depreciation expense, higher property taxes, higher interest expense and dilution from additional shares outstanding as discussed below.

Diluted earnings per share figures give effect to dilutive potential common stock using the treasury stock method. See Note 1 to the condensed consolidated financial statements.

Dividends Declared

SCANA’s Board of Directors has declared the following dividends on common stock during 2013:

Declaration Date	Dividend Per Share	Record Date	Payment Date
February 20, 2013	$0.5075	March 11, 2013	April 1, 2013
April 25, 2013	$0.5075	June 10, 2013	July 1, 2013
July 31, 2013	$0.5075	September 10, 2013	October 1, 2013

When a dividend payment date falls on a weekend or holiday, the payment is made the following business day.

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Electric Operations

Electric Operations is comprised of the electric operations of SCE&G, GENCO and Fuel Company. Electric operations sales margin (including transactions with affiliates) was as follows:

	Second Quarter			Year to Date		
Millions of dollars	2013	Change	2012	2013	Change	2012
Operating revenues	$611.6	2.9 %	$594.1	$1,197.2	4.9 %	$1,141.4
Less: Fuel used in generation	189.2	(5.0)%	199.2	376.9	(1.3)%	381.9
Purchased power	8.8	91.3 %	4.6	15.8	53.4 %	10.3
Margin	$413.6	6.0 %	$390.3	$804.5	7.4 %	$749.2

Second Quarter

Electric margin increased primarily due to base rate increases under the BLRA of $12.1 million and higher retail electric base rates of $15.1 million approved in the December 2012 rate order.

Year to Date

Electric margin increased primarily due to base rate increases under the BLRA of $25.1 million and higher retail electric base rates of $32.0 million approved in the December 2012 rate order.

Sales volumes (in GWh) related to the electric margin above, by class, were as follows:

	Second Quarter			Year to Date		
Classification	2013	Change	2012	2013	Change	2012
Residential	1,784	(0.8)%	1,799	3,642	4.4 %	3,490
Commercial	1,777	(3.7)%	1,846	3,446	(1.3)%	3,490
Industrial	1,518	0.3 %	1,514	2,921	0.8 %	2,899
Other	144	(2.0)%	147	279	(1.1)%	282
Total Retail Sales	5,223	(1.6)%	5,306	10,288	1.2 %	10,161
Wholesale	228	(63.4)%	623	491	(60.9)%	1,257
Total Sales	5,451	(8.1)%	5,929	10,779	(5.6)%	11,418

Second Quarter

Retail sales volume decreased primarily due to lower average use, partially offset by customer growth. The decrease in wholesale sales is primarily due to the expiration of two customer contracts.

Year to Date

Retail sales volume increased primarily due to customer growth and the effects of weather. The decrease in wholesale sales is primarily due to the expiration of two customer contracts.

Gas Distribution

Gas Distribution is comprised of the local distribution operations of SCE&G and PSNC Energy. Gas distribution sales margin (including transactions with affiliates) was as follows:

	Second Quarter			Year to Date		
Millions of dollars	2013	Change	2012	2013	Change	2012
Operating revenues	$154.7	23.4 %	$125.4	$534.0	33.5 %	$400.0

Less: Gas purchased for resale	85.5	49.2 %	57.3	308.2	65.8 %	185.9
Margin	$69.2	1.6 %	$68.1	$225.8	5.5 %	$214.1

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Second Quarter

Margin at PSNC Energy increased primarily due to residential customer growth and increased industrial usage.

Year to Date

Margin at SCE&G increased primarily due to the SCPSC-approved increase in base rates under the RSA which became effective with the first billing cycle of November 2012. Margin at PSNC Energy increased primarily due to residential customer growth and increased industrial usage.

Sales volumes (in MMBTU) by class, including transportation, were as follows:

	Second Quarter			Year to Date		
Classification (in thousands)	2013	Change	2012	2013	Change	2012
Residential	3,866	23.0 %	3,142	25,240	38.9 %	18,168
Commercial	4,886	4.4 %	4,682	15,644	19.9 %	13,048
Industrial	5,438	8.2 %	5,025	11,599	10.8 %	10,470
Transportation	9,787	9.6 %	8,928	20,988	9.6 %	19,152
Total	23,977	10.1 %	21,777	73,471	20.8 %	60,838

Second Quarter and Year to Date

Total sales volumes at SCE&G increased primarily due to the effects of weather. Total sales volumes at PSNC Energy increased primarily due to the effects of weather and residential customer growth as well as increased industrial usage.

Retail Gas Marketing

Retail Gas Marketing is comprised of SCANA Energy, which operates in Georgia's natural gas market. Retail Gas Marketing operating revenues and net income were as follows:

	Second Quarter			Year to Date		
Millions of dollars	2013	Change	2012	2013	Change	2012
Operating revenues	$79.2	11.1 %	$71.3	$258.2	15.2 %	$224.1
Net income (loss)	(2.7)	(15.6)%	(3.2)	19.4	*	7.9

* Greater than 100%

Second Quarter and Year to Date

Changes in operating revenues and net income (loss) are primarily due to higher demand in 2013 as a result of weather.

Energy Marketing

Energy Marketing is comprised of the Company's non-regulated marketing operations, excluding SCANA Energy. Energy Marketing operating revenues and net income were as follows:

	Second Quarter			Year to Date		
Millions of dollars	2013	Change	2012	2013	Change	2012
Operating revenues	$216.4	53.6 %	$140.9	$425.5	42.3 %	$299.0
Net Income	1.0	(44.4)%	1.8	3.7	2.8 %	3.6

Second Quarter

Operating revenues increased due to higher market prices. Net income decreased due to higher costs and lower margins on sales.

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Year to Date

Operating revenues increased due to higher sales volume and higher market prices. Net income increased due to an increase in industrial customer consumption.

Other Operating Expenses

Other operating expenses were as follows:

	Second Quarter			Year to Date		
Millions of dollars	2013	Change	2012	2013	Change	2012
Other operation and maintenance	$170.8	0.6 %	$169.8	$346.9	0.6 %	$344.9
Depreciation and amortization	94.5	5.9 %	89.2	187.8	5.6 %	177.9
Other taxes	54.5	3.0 %	52.9	109.3	3.6 %	105.5

Second Quarter

Other operation and maintenance expenses increased by $4.1 million due to incremental expenses associated with the December 2012 rate order and by $2.0 million due to higher generation expenses. These increases were partially offset by $1.9 million due to lower compensation and by other general expenses. Depreciation and amortization expense increased $3.3 million due to the recognition of depreciation expense associated with the Wateree Station scrubber which was provided for in the December 2012 rate order and due to other net plant additions. Other taxes increased primarily due to higher property taxes.

Year to Date

Other operation and maintenance expenses increased by $8.2 million due to incremental expenses associated with the December 2012 rate order. These increases were partially offset by $1.5 million due to lower generation expenses, by $2.0 million due to lower compensation and by other general expenses. Depreciation and amortization expense increased $6.6 million due to the recognition of depreciation expense associated with the Wateree Station scrubber which was provided for in the December 2012 rate order and due to other net plant additions. Other taxes increased primarily due to higher property taxes.

Other Income (Expense)

Other income (expense) includes the results of certain incidental (non-utility) activities, the activities of certain non-regulated subsidiaries and AFC. AFC is a utility accounting practice whereby a portion of the cost of both equity and borrowed funds used to finance construction (which is shown on the balance sheet as construction work in progress) is capitalized. The Company includes an equity portion of AFC in nonoperating income and a debt portion of AFC in interest charges (credits), both of which have the effect of increasing reported net income.

Interest Expense

Interest charges increased primarily due to increased borrowings.

Income Taxes

Income taxes for the three and six months ended June 30, 2013 were higher than the same periods in 2012 primarily due to higher income. The increase in the effective tax rate for year to date 2013 is principally attributable to lower recognition of EIZ Credits upon the completion of the amortization of certain such credits in 2012.

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LIQUIDITY AND CAPITAL RESOURCES

The Company anticipates that its contractual cash obligations will be met through internally generated funds, the incurrence of additional short- and long-term indebtedness and sales of equity securities. The Company expects that, barring a future impairment of the capital markets, it has or can obtain adequate sources of financing to meet its projected cash requirements for the foreseeable future, including the cash requirements for nuclear construction and refinancing maturing long-term debt. The Company's ratio of earnings to fixed charges for the six and 12 months ended June 30, 2013 was 3.22 and 3.13, respectively.

The Company is obligated with respect to an aggregate of $67.8 million of industrial revenue bonds which are secured by letters of credit issued by Branch Banking and Trust Company. These letters of credit expire, subject to renewal, in the fourth quarter of 2014.

At June 30, 2013, the Company had net available liquidity of approximately $1.6 billion. The Company's credit agreements total an aggregate of $1.8 billion, of which $200 million is scheduled to expire in October 2015 and the remainder is scheduled to expire in October 2017. The Company regularly monitors the commercial paper and short-term credit markets to optimize the timing of repayment of outstanding balances on its draws, if any, from the credit facilities. The Company's long-term debt portfolio has a weighted average maturity of approximately 18 years and bears an average interest cost of 5.7%. Substantially all of the long-term debt bears fixed interest rates or is swapped to fixed. To further preserve liquidity, the Company rigorously reviews its projected capital expenditures and operating costs and adjusts them where possible without impacting safety, reliability, and core customer service.

SCE&G has obtained FERC authority to issue short-term indebtedness and to assume liabilities as a guarantor (pursuant to Section 204 of the Federal Power Act). SCE&G may issue unsecured promissory notes, commercial paper and direct loans in amounts not to exceed $1.6 billion outstanding with maturity dates of one year or less, and may enter into guaranty agreements in favor of lenders, bankers, and dealers in commercial paper in amounts not to exceed $600 million. GENCO has obtained FERC authority to issue short-term indebtedness not to exceed $150 million outstanding with maturity dates of one year or less. The authority described herein will expire in October 2014.

SCANA issued approximately $51 million of stock during the six months ended June 30, 2013 through various compensation and dividend reinvestment plans. Similar issuances are expected in future periods. In addition, on March 5, 2013, SCANA settled all forward sales contracts related to its common stock through the issuance of approximately 6.6 million common shares, resulting in net proceeds of approximately $196 million.

On May 28, 2013, Standard & Poor's Ratings Services revised the rating outlook of SCANA, SCE&G and PSNC Energy to "negative" from "stable" but affirmed the corporate credit ratings for each of these entities.

In connection with the expected delays in the substantial completion of the New Units described in Note 9 to the condensed consolidated financial statements, SCE&G's current preliminary estimates of its capital expenditures for new nuclear construction (including transmission) for 2013 through 2015, which are subject to continuing review and adjustment, are $740 million in 2013, $979 million in 2014, and $881 million in 2015.

OTHER MATTERS

For information related to environmental matters, nuclear generation, and claims and litigation, see Note 9 to the condensed consolidated financial statements.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Interest Rate Risk - The Company's market risk exposures relative to interest rate risk have not changed materially compared with the Company's Annual Report on Form 10-K for the year ended December 31, 2012. Interest rates on substantially all of the Company's outstanding long-term debt, other than credit facility draws, are fixed either through the issuance of fixed rate debt or through the use of interest rate derivatives. The Company is not aware of any facts or circumstances that would significantly affect exposures on existing indebtedness in the near future.

For further discussion of changes in long-term debt and interest rate derivatives, see ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS – LIQUIDITY AND CAPITAL RESOURCES and also Notes 4 and 6 of the condensed consolidated financial statements.

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Commodity price risk - The Company uses derivative instruments to hedge forward purchases and sales of natural gas, which create market risks of different types. The SCPSC authorized the suspension of SCE&G's natural gas hedging program in January 2012. The fair value of SCE&G's derivative instruments remaining to be settled were not significant for any period presented. See Note 6 of the condensed consolidated financial statements. The following tables provide information about the Company’s financial instruments that are sensitive to changes in natural gas prices. Weighted average settlement prices are per 10,000 MMBTU. Fair value represents quoted market prices for these or similar instruments.

	Expected Maturity			Expected Maturity	
Futures - Long	2013	2014	Options Purchased Call - Long	2013	2014
Settlement Price (a)	3.64	3.77	Strike Price (a)	4.05	4.09
Contract Amount (b)	8.5	7.1	Contract Amount (b)	14.1	13.9
Fair Value (b)	8.0	6.8	Fair Value (b)	0.5	0.8

(a) Weighted average, in dollars
(b) Millions of dollars

	Expected Maturity				
Swaps	2013	2014	2015	2016	2017
Commodity Swaps:					
Pay fixed/receive variable (b)	29.2	34.9	14.3	8.2	0.5
Average pay rate (a)	4.3972	4.4806	5.1180	4.8661	4.2850
Average received rate (a)	3.6638	3.8953	4.1439	4.3286	4.5695
Fair value (b)	24.3	30.4	11.6	7.3	0.5
Pay variable/receive fixed (b)	14.4	20.7	11.5	7.3	0.5
Average pay rate (a)	3.6356	3.8987	4.1440	4.3286	4.5695
Average received rate (a)	4.3831	4.5877	5.1366	4.8925	4.2900
Fair value (b)	17.3	24.4	14.2	8.2	0.5
Basis Swaps:					
Pay variable/receive variable (b)	3.5	1.1	0.5	—	—
Average pay rate (a)	3.6322	3.9613	4.2721	—	—
Average received rate (a)	3.6149	3.9461	4.2575	—	—
Fair value (b)	3.5	1.1	0.5	—	—

(a) Weighted average, in dollars
(b) Millions of dollars

ITEM 4. CONTROLS AND PROCEDURES

As of June 30, 2013, SCANA conducted an evaluation under the supervision and with the participation of its management, including its CEO and CFO, of (a) the effectiveness of the design and operation of its disclosure controls and procedures and (b) any change in its internal control over financial reporting. Based on this evaluation, the CEO and CFO concluded that, as of June 30, 2013, SCANA’s disclosure controls and procedures were effective. There has been no change in SCANA’s internal control over financial reporting during the quarter ended June 30, 2013 that has materially affected or is reasonably likely to materially affect SCANA’s internal control over financial reporting.

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SOUTH CAROLINA ELECTRIC & GAS COMPANY
FINANCIAL SECTION

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Item 1. FINANCIAL STATEMENTS
SOUTH CAROLINA ELECTRIC & GAS COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

Millions of dollars	June 30, 2013	December 31, 2012
Assets		
Utility Plant In Service	$10,242	$10,096
Accumulated Depreciation and Amortization	(3,414)	(3,322)
Construction Work in Progress	2,356	2,073
Plant to be Retired, Net	351	362
Nuclear Fuel, Net of Accumulated Amortization	267	166
Utility Plant, Net ($679 and $640 related to VIEs)	9,802	9,375
Nonutility Property and Investments:		
Nonutility property, net of accumulated depreciation	64	57
Assets held in trust, net - nuclear decommissioning	95	94
Other investments	2	3
Nonutility Property and Investments, Net	161	154
Current Assets:		
Cash and cash equivalents	50	51
Receivables, net of allowance for uncollectible accounts of $2 and $3	492	483
Affiliated receivables	12	2
Inventories (at average cost):		
Fuel and gas supply	183	203
Materials and supplies	128	126
Emission allowances	1	1
Prepayments and other	161	143
Total Current Assets ($181 and $206 related to VIEs)	1,027	1,009
Deferred Debits and Other Assets:		
Regulatory assets	1,352	1,377
Other	190	189
Total Deferred Debits and Other Assets ($47 and $54 related to VIEs)	1,542	1,566
Total	$12,532	$12,104

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Millions of dollars	June 30, 2013	December 31, 2012
Capitalization and Liabilities		
Common equity	$4,234	$3,929
Noncontrolling interest	116	114
Long-Term Debt, net	4,043	3,557
Total Capitalization	8,393	7,600
Current Liabilities:		
Short-term borrowings	238	449
Current portion of long-term debt	16	165
Accounts Payable	269	281
Affiliated Payables	109	124
Customer deposits and customer prepayments	53	51
Taxes accrued	113	151
Interest accrued	64	63
Dividends declared	64	46
Derivative financial instruments	2	66
Other	38	50
Total Current Liabilities	966	1,446
Deferred Credits and Other Liabilities:		
Deferred income taxes, net	1,506	1,479
Deferred investment tax credits	34	36
Asset retirement obligations	543	535
Postretirement benefits	255	254
Regulatory liabilities	753	665
Other	82	89
Total Deferred Credits and Other Liabilities	3,173	3,058
Commitments and Contingencies (Note 9)	—	—
Total	$12,532	$12,104

See Notes to Condensed Consolidated Financial Statements.

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SOUTH CAROLINA ELECTRIC & GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
Millions of dollars	2013	2012	2013	2012
Operating Revenues:				
Electric	$612	$594	$1,197	$1,141
Gas	84	67	227	183
Total Operating Revenues	696	661	1,424	1,324
Operating Expenses:				
Fuel used in electric generation	189	199	377	382
Purchased power	9	4	16	10
Gas purchased for resale	54	37	131	96
Other operation and maintenance	135	134	274	272
Depreciation and amortization	79	74	156	147
Other taxes	50	48	99	96
Total Operating Expenses	516	496	1,053	1,003
Operating Income	180	165	371	321
Other Expense:		156,311		
Other expense	(4)	(3)	(7)	(7)
Interest charges, net of allowance for borrowed funds used during construction of $3, $3, $5 and $4	(54)	(52)	(108)	(103)
Allowance for equity funds used during construction	6	4	9	7
Total Other Expense	(52)	(51)	(106)	(103)
Income Before Income Tax Expense	128	114	265	218
Income Tax Expense	40	36	85	69
Net Income	88	78	180	149
Net Income Attributable to Noncontrolling Interest	(3)	(2)	(6)	(6)
Earnings Available to Common Shareholder	$85	$76	$174	$143
Dividends Declared on Common Stock	$64	$54	$128	$107

See Notes to Condensed Consolidated Financial Statements.

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SOUTH CAROLINA ELECTRIC & GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
Millions of dollars	2013	2012	2013	2012
Net Income	$88	$78	$180	$149
Other Comprehensive Income, net of tax:				
Amortization of deferred employee benefit plan costs reclassified to net income, net of tax of $-, $-, $- and $-	—	—	—	—
Total Comprehensive Income	88	78	180	149
Comprehensive income attributable to noncontrolling interest	(3)	(2)	(6)	(6)
Comprehensive income available to common shareholder	$85	$76	$174	$143

Accumulated other comprehensive loss totaled $3.9 million as of June 30, 2013 and $4.0 million as of December 31, 2012.

See Notes to Condensed Consolidated Financial Statements.

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SOUTH CAROLINA ELECTRIC & GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Six Months Ended June 30,	
Millions of dollars	2013	2012
Cash Flows From Operating Activities:		
Net income	$180	$149
Adjustments to reconcile net income to net cash provided from operating activities:		
Losses from equity method investments	1	2
Deferred income taxes, net	26	56
Depreciation and amortization	156	147
Amortization of nuclear fuel	27	26
Allowance for equity funds used during construction	(9)	(7)
Cash provided (used) by changes in certain assets and liabilities:		
Receivables	(12)	3
Inventories	(4)	(50)
Prepayments and other	(45)	(74)
Regulatory assets	9	20
Regulatory liabilities	58	29
Accounts payable	(4)	(5)
Taxes accrued	(38)	(11)
Interest accrued	1	5
Changes in other assets	(31)	24
Changes in other liabilities	(12)	(45)
Net Cash Provided From Operating Activities	303	269
Cash Flows From Investing Activities:		
Property additions and construction expenditures	(478)	(544)
Proceeds from investments (including derivative collateral posted)	132	98
Purchase of investments (including derivative collateral posted)	(104)	(121)
Payments upon interest rate contract settlement	(49)	—
Proceeds from interest rate contract settlement	43	13
Net Cash Used For Investing Activities	(456)	(554)
Cash Flows From Financing Activities:		
Proceeds from issuance of long-term debt	451	248
Repayment of long-term debt	(218)	(10)
Dividends	(110)	(92)
Contributions from parent	255	51
Short-term borrowings –affiliate, net	(15)	12
Short-term borrowings, net	(211)	74
Net Cash Provided From Financing Activities	152	283
Net Decrease In Cash and Cash Equivalents	(1)	(2)
Cash and Cash Equivalents, January 1	51	16
Cash and Cash Equivalents, June 30	$50	$14
Supplemental Cash Flow Information:		
Cash paid for– Interest (net of capitalized interest of $5 and $4)	$99	$92
– Income taxes	24	—
Noncash Investing and Financing Activities:		

Accrued construction expenditures	85	51
Capital leases	3	2
Nuclear fuel purchase	97	—

See Notes to Condensed Consolidated Financial Statements.

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SOUTH CAROLINA ELECTRIC & GAS COMPANY
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
For the Three and Six Months Ended June 30, 2013 and 2012
(Unaudited)

The following notes should be read in conjunction with the Notes to Consolidated Financial Statements appearing in SCE&G's Annual Report on Form 10-K for the year ended December 31, 2012. These are interim financial statements and, due to the seasonality of Consolidated SCE&G's business and matters that may occur during the rest of the year, the amounts reported in the Condensed Consolidated Statements of Income are not necessarily indicative of amounts expected for the full year. In the opinion of management, the information furnished herein reflects all adjustments, all of a normal recurring nature, which are necessary for a fair statement of the results for the interim periods reported.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amount of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Variable Interest Entity

SCE&G has determined that it is the primary beneficiary of GENCO and Fuel Company (which are considered to be VIEs) and, accordingly, the accompanying condensed consolidated financial statements include the accounts of SCE&G, GENCO and Fuel Company. The equity interests in GENCO and Fuel Company are held solely by SCANA, SCE&G's parent. Accordingly, GENCO's and Fuel Company's equity and results of operations are reflected as noncontrolling interest in Consolidated SCE&G's condensed consolidated financial statements.

GENCO owns a coal-fired electric generating station with a 605 MW net generating capacity (summer rating). GENCO's electricity is sold, pursuant to a FERC-approved tariff, solely to SCE&G under the terms of a power purchase agreement and related operating agreement. The effects of these transactions are eliminated in consolidation. Substantially all of GENCO's property (carrying value of approximately $477 million) serves as collateral for its long-term borrowings. Fuel Company acquires, owns and provides financing for SCE&G's nuclear fuel, certain fossil fuels and emission allowances. See also Note 4.

Plant to be Retired

In 2012, SCE&G announced its intention to retire six coal-fired units by 2018, subject to future developments in environmental regulations, among other matters. These units had an aggregate generating capacity (summer 2012) of 730 MW. One of these units (90 MW) was retired in 2012 and its net carrying value is recorded in regulatory assets as unrecovered plant (see Note 2). In June 2013, SCE&G approved a plan to accelerate the retirement of two more of these units (295 MW) by the end of 2013. The net carrying value of the remaining units to be retired (including these two units) totaled $351 million at June 30, 2013 and is included in Plant to be Retired, Net in the consolidated financial statements. In connection with their retirement, SCE&G expects to be allowed a recovery of and a return on the net carrying value of these remaining units through rates. In the meantime, these units remain in rate base, and SCE&G continues to depreciate them using composite straight-line rates approved by the SCPSC.

2. RATE AND OTHER REGULATORY MATTERS

Rate Matters

Electric

SCE&G's retail electric rates include a cost of fuel component approved by the SCPSC which may be adjusted periodically to reflect changes in the price of fuel purchased by SCE&G. In April 2012, the SCPSC approved SCE&G's request to decrease the total fuel cost component of its retail electric rates, and approved a settlement agreement among SCE&G, the ORS and SCEUC in which SCE&G agreed to recover an amount equal to its actual under-collected balance of

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base fuel and variable environmental costs as of April 30, 2012, or $80.6 million, over a 12-month period beginning with the first billing cycle of May 2012.

In the December 2012 rate order, the SCPSC authorized SCE&G to reduce the base fuel cost component of its retail electric rates and, in doing so, stated that SCE&G may not adjust its base fuel cost component prior to the last billing cycle of April 2014, except where necessary due to extraordinary unforeseen economic or financial conditions. In February 2013, in connection with its annual review of base rates for fuel costs, SCE&G requested authorization to reduce its environmental fuel cost component effective with the first billing cycle of May 2013. Consistent with the December 2012 rate order, however, SCE&G did not request any adjustment to its base fuel cost component. On March 14, 2013, SCE&G, ORS and the SCEUC entered into a settlement agreement accepting the proposed lower environmental fuel cost component effective with the first billing cycle of May 2013, and providing for the accrual of certain debt-related carrying costs on a portion of the undercollected balance of fuel costs.The SCPSC issued an order dated April 30, 2013, adopting and approving the settlement agreement and approving SCE&G's total fuel cost component.

On December 19, 2012, the SCPSC approved a 4.23% overall increase in SCE&G's retail electric base rates, effective January 1, 2013, and authorized an allowed return on common equity of 10.25%. The SCPSC also approved a mid-period reduction to the cost of fuel component in rates (as discussed above), a reduction in the DSM Programs component rider to retail rates, and the recovery of and a return on the net carrying value of certain retired generating plant assets described below. By order dated February 7, 2013, the SCPSC denied the SCEUC's petition for rehearing of this order.

The eWNA is designed to mitigate the efforts of abnormal weather on residential and commercial customers' bills and is based on a 15 year historical average of temperatures. In connection with the December 2012 rate order, SCE&G agreed to perform a study of alternative structures for the eWNA which may be used to modify or terminate eWNA in the future. The study was completed and filed with the SCPSC on June 28, 2013. In the study, SCE&G proposed that no adjustment or modification to the eWNA be made at this time. SCE&G cannot predict what action the SCPSC may take, if any, as a result of this study.

In February 2013, SCE&G filed an IRP with the SCPSC. The IRP evaluates future electric generation needs based on a variety of factors, including customer energy demands, EPA regulations, reserve margins and fuel costs. The IRP identified a total of six coal-fired units that SCE&G retired or intends to retire by 2018, subject to future developments in environmental regulations, among other matters. One of these units was retired in 2012, and its net carrying value is recorded in regulatory assets as unrecovered plant and is being amortized over its original remaining useful life. The net carrying value of the remaining units is included in Plant to be Retired, Net in the consolidated financial statements. In connection with their retirement, SCE&G expects to be allowed a recovery of and a return on the net carrying value of these remaining units through rates. In the meantime, these units remain in rate base, and SCE&G continues to depreciate them using composite straight-line rates approved by the SCPSC. As discussed in Note 1, in June 2013, SCE&G approved a plan to accelerate the retirement of two of the units to be completed by December 31, 2013.

SCE&G's DSM Programs for electric customers provide for an annual rider, approved by the SCPSC, to allow recovery of the costs and net lost revenue associated with the DSM Programs, along with an incentive for investing in such programs. SCE&G submits annual filings in January to the SCPSC regarding the DSM Programs, net lost revenues, program costs, incentives and net program benefits. The SCPSC has approved the following rate changes pursuant to annual DSM Programs filings, which changes became effective as indicated:

Year	Effective	Amount
2012	First billing cycle of May	$19.6 million
2011	First billing cycle of June	$7.0 million

In January 2013, SCE&G filed its annual update on DSM Programs and a petition for an update to the rate rider, requesting an increase of approximately $27.2 million. On April 1, 2013, ORS filed a report of its review of SCE&G's DSM Programs petition with the SCPSC. ORS proposed that SCE&G recover the net lost revenue component of the rider of $20.6 million over a 24-month period effective for bills rendered on and after the first billing cycle in May 2013. ORS also recommended that SCE&G defer a portion of net lost revenue component in a regulatory asset and recover those amounts over a 12-month period effective for bills rendered on and after the first billing cycle in May 2014. SCE&G agreed with ORS's recommendations. On April 30, 2013, the SCPSC approved SCE&G's request to update its DSM Programs rider, as modified by the agreement between ORS and SCE&G, effective for bills rendered on and after the first billing cycle of May 2013.

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SCE&G's initial authorization to operate its DSM Programs expires November 30, 2013. On May 31, 2013, SCE&G filed a request with the SCPSC for approval to extend the operation of its portfolio of DSM Programs. SCE&G also requested approval to continue the use of an annual rate rider which (i) maintains the same terms and conditions currently in effect for the recovery of costs associated with the proposed DSM Programs, the net lost revenue associated with its DSM Programs, and an appropriate incentive for investing in such programs and (ii) modifies the opt-out requirements for industrial customers. SCE&G requested that the proposed DSM Programs rider be effective December 1, 2013.

Electric – BLRA

In November 2012, the SCPSC approved an updated construction schedule and additional updated capital costs of $278 million (SCE&G's portion in 2007 dollars). The November 2012 order approved additional identifiable capital costs of approximately $1 million (SCE&G's portion in 2007 dollars) related to new federal healthcare laws, information security measures, and certain minor design modifications; approximately $8 million (SCE&G's portion in 2007 dollars) related to transmission infrastructure; and approximately $132 million (SCE&G's portion in 2007 dollars) related to additional labor for the oversight of the New Units during construction and for preparing to operate the New Units, and facilities and information technology systems required to support the New Units and their personnel. In addition, the order approved revised substantial completion dates for the New Units based on the March 30, 2012 issuance of the COL and the amounts agreed upon by SCE&G and the Consortium in July 2012 to resolve claims for costs related to COL delays, design modifications of the shield building and certain pre-fabricated structural modules for the New Units and unanticipated rock conditions at the site. Thereafter, two parties filed separate petitions requesting that the SCPSC reconsider its November 2012 order. On December 12, 2012, the SCPSC denied both petitions. In March 2013, both parties appealed the SCPSC's order to the South Carolina Supreme Court. SCE&G is unable to predict the outcome of these appeals.

Under the BLRA, SCE&G is allowed to file revised rates with the SCPSC each year to incorporate the financing cost of any incremental construction work in progress incurred for new nuclear generation. Requested rate adjustments are based on SCE&G’s updated cost of debt and capital structure and on an allowed return on common equity of 11.0%. The SCPSC has approved the following rate changes under the BLRA effective for bills rendered on and after October 30 in the years indicated:

Year	Action		Amount
2012	2.3	% Increase	$52.1 million
2011	2.4	% Increase	$52.8 million

On May 31, 2013, SCE&G filed its annual request for approval of revised rates under the BLRA. On July 30, 2013, ORS filed a report of its review of SCE&G's request. ORS proposes that SCE&G be allowed to increase its rates in the amount of $67.2 million, or 2.87%. If approved, the revised rates will be effective for bills rendered on and after October 30, 2013.

Gas

The RSA is designed to reduce the volatility of costs charged to customers by allowing for more timely recovery of the costs that regulated utilities incur related to natural gas infrastructure. The SCPSC has approved the following rate changes pursuant to annual RSA filings effective with the first billing cycle of November in the years indicated:

Year	Action		Amount
2012	2.1	% Increase	$7.5 million
2011	2.1	% Increase	$8.6 million

On June 5, 2013, SCE&G submitted its annual RSA filing with the SCPSC for the 12-month period ending March 31, 2013. SCE&G earned a return on its gas distribution operations, after proforma adjustments, that is within the range of its allowable rate of return on common equity. Therefore, SCE&G did not request any adjustments to its rates.

SCE&G's natural gas tariffs include a PGA clause that provides for the recovery of actual gas costs incurred. SCE&G's gas rates are calculated using a methodology which may adjust the cost of gas monthly based on a 12-month rolling average. The annual PGA hearing to review SCE&G's gas purchasing policies and procedures was held in November 2012 before the SCPSC. The SCPSC issued an order in December 2012 finding that SCE&G's gas purchasing policies and practices during the review period of August 1, 2011 through July 31, 2012, were reasonable and prudent. The next annual PGA hearing is scheduled for November 7, 2013.

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Regulatory Assets and Regulatory Liabilities

Consolidated SCE&G has significant cost-based, rate-regulated operations and recognizes in its financial statements certain revenues and expenses in different time periods than do enterprises that are not rate-regulated. As a result, Consolidated SCE&G has recorded regulatory assets and regulatory liabilities, which are summarized in the following tables. Substantially all regulatory assets are either explicitly excluded from rate base or are effectively excluded from rate base due to their being offset by related liabilities.

Millions of dollars	June 30, 2013	December 31, 2012
Regulatory Assets:		
Accumulated deferred income taxes	$248	$248
Under collections – electric fuel adjustment clause	71	66
Environmental remediation costs	38	39
AROs and related funding	311	304
Franchise agreements	33	36
Deferred employee benefit plan costs	393	405
Planned major maintenance	—	6
Deferred losses on interest rate derivatives	128	151
Deferred pollution control costs	38	38
Unrecovered plant	19	20
Other	73	64
Total Regulatory Assets	$1,352	$1,377
Regulatory Liabilities:		
Accumulated deferred income taxes	$20	$21
Asset removal costs	517	507
Storm damage reserve	27	27
Deferred gains on interest rate derivatives	185	110
Planned major maintenance	4	—
Total Regulatory Liabilities	$753	$665

Accumulated deferred income tax liabilities that arose from utility operations that have not been included in customer rates are recorded as a regulatory asset. Substantially all of these regulatory assets relate to depreciation and are expected to be recovered over the remaining lives of the related property which may range up to approximately 70 years. Similarly, accumulated deferred income tax assets arising from deferred investment tax credits are recorded as a regulatory liability.

Under-collections - electric fuel adjustment clause represent amounts due from customers pursuant to the fuel adjustment clause as approved by the SCPSC during annual hearings which are not expected to be recovered in retail electric rates within 12 months.

Environmental remediation costs represent costs associated with the assessment and clean-up of MGP sites currently or formerly owned by SCE&G. These regulatory assets are expected to be recovered over periods of up to approximately 27 years.

ARO and related funding represents the regulatory asset associated with the legal obligation to decommission and dismantle Summer Station and conditional AROs. These regulatory assets are expected to be recovered over the related property lives and periods of decommissioning which may range up to approximately 90 years.

Franchise agreements represent costs associated with electric and gas franchise agreements with the cities of Charleston and Columbia, South Carolina. Based on an SCPSC order, SCE&G began amortizing these amounts through cost of service rates in February 2003 over approximately 20 years.

Employee benefit plan costs of the regulated utilities have historically been recovered as they have been recorded under generally accepted accounting principles. Deferred employee benefit plan costs represent amounts of pension and other postretirement benefit costs which were accrued as liabilities and treated as regulatory assets pursuant to FERC guidance, and costs deferred pursuant to specific SCPSC regulatory orders. In connection with the December 2012 rate order, approximately $63 million of deferred pension costs for electric operations are to be recovered through utility rates over approximately 30 years. The remainder of the deferred benefit costs are expected to be recovered through utility rates, primarily over average service periods of participating employees, or up to approximately 12 years.

Planned major maintenance related to certain fossil fueled turbine/generation equipment and nuclear refueling outages is accrued in periods other than when incurred, as approved pursuant to specific SCPSC orders. SCE&G collects $18.4 million annually for fossil fueled turbine/generation equipment maintenance. Through December 31, 2012, nuclear refueling charges were accrued during each 18-month refueling outage cycle as a component of cost of service. In connection with the December 2012 rate order, effective January 1, 2013, SCE&G began to collect and accrue $17.2 million annually for nuclear-related refueling charges.

Deferred losses or gains on interest rate derivatives represent the effective portions of changes in fair value and payments made or received upon termination of certain interest rate derivatives designated as cash flow hedges. These amounts are expected to be amortized to interest expense over the lives of the underlying debt, up to approximately 30 years.

Deferred pollution control costs represent deferred depreciation and operating and maintenance costs associated with the scrubbers installed at Wateree and Williams Stations pursuant to specific regulatory orders. Such costs are being recovered through utility rates over periods up to 30 years.

Unrecovered plant represents the net book value of a coal-fired generating unit retired from service prior to being fully depreciated. Pursuant to the December 2012 rate order, SCE&G is amortizing these amounts over the unit's original remaining useful life of approximately 14 years. Unamortized amounts are included in rate base.

Various other regulatory assets are expected to be recovered in rates over periods of up to approximately 30 years.

Asset removal costs represent estimated net collections through depreciation rates of amounts to be incurred for the removal of assets in the future.

The storm damage reserve represents an SCPSC-approved collection through SCE&G electric rates, capped at $100 million, which can be applied to offset incremental storm damage costs in excess of $2.5 million in a calendar year. Pursuant to specific regulatory orders, SCE&G has suspended storm damage reserve collection through rates indefinitely.

The SCPSC or the FERC has reviewed and approved through specific orders most of the items shown as regulatory assets. Other regulatory assets include, but are not limited to, certain costs which have not been approved for recovery by the SCPSC or by the FERC. In recording such costs as regulatory assets, management believes the costs will be allowable under existing rate-making concepts that are embodied in rate orders received by SCE&G. The costs are currently not being recovered, but are expected to be recovered through rates in future periods. In the future, as a result of deregulation or other changes in the regulatory environment or changes in accounting requirements, Consolidated SCE&G could be required to write off its regulatory assets and liabilities. Such an event could have a material effect on Consolidated SCE&G's results of operations, liquidity or financial position in the period the write-off would be recorded.

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3. EQUITY

Changes in common equity during the six months ended June 30, 2013 and 2012 were as follows:

Millions of dollars	Common Equity	Noncontrolling Interest	Total Equity
Balance at January 1, 2013	$3,929	$114	$4,043
Capital contribution from parent	255	—	255
Dividends declared	(124)	(4)	(128)
Comprehensive income	174	6	180
Balance as of June 30, 2013	$4,234	$116	$4,350
Balance at January 1, 2012	$3,665	$108	$3,773
Capital contribution from parent	51	—	51
Dividends declared	(103)	(4)	(107)
Comprehensive income	143	6	149
Balance as of June 30, 2012	$3,756	$110	$3,866

SCE&G had 50 million shares of common stock authorized as of June 30, 2013 and December 31, 2012, of which 40.3 million were issued and outstanding during all periods presented. SCE&G had 20 million shares of preferred stock authorized as of June 30, 2013 and December 31, 2012, of which 1,000 shares were issued and outstanding during all periods presented. All issued and outstanding shares of SCE&G's common and preferred stock are held by SCANA.

Reclassifications from AOCI into earnings of the amortization of deferred employee benefit costs were not significant for any period presented.

4. LONG-TERM DEBT AND LIQUIDITY

Long-term Debt

In June 2013, SCE&G issued $400 million of 4.60% first mortgage bonds due June 15, 2043. Proceeds from this sale were used to pay at maturity $150 million of its 7.125% first mortgage bonds due June 15, 2013, to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures, and for general corporate purposes.

In January 2013, JEDA issued at a premium, for the benefit of SCE&G, $39.5 million of 4.0% tax-exempt industrial revenue bonds due February 1, 2028, and $14.7 million of 3.63% tax-exempt industrial revenue bonds due February 1, 2033. Proceeds from these sales were loaned by JEDA to SCE&G and, together with other available funds, were used to redeem prior to maturity $56.9 million of 5.2% industrial revenue bonds due November 1, 2027.

Substantially all of Consolidated SCE&G’s electric utility plant is pledged as collateral in connection with long-term debt. Consolidated SCE&G is in compliance with all debt covenants.

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Liquidity

SCE&G (including Fuel Company) had available the following committed LOC, and had outstanding the following LOC advances, commercial paper, and LOC-supported letter of credit obligations:

Millions of dollars	June 30, 2013	December 31, 2012
Lines of credit:		
Total committed long-term	$1,400	$1,400
LOC advances	—	—
Weighted average interest rate	—	—
Outstanding commercial paper (270 or fewer days)	$238	$449
Weighted average interest rate	0.30 %	0.42 %
Letters of credit supported by LOC	$0.3	$0.3
Available	$1,162	$951

SCE&G and Fuel Company are parties to five-year credit agreements in the amount of $1.2 billion (of which $500 million relates to Fuel Company) which expire in October 2017. In addition, SCE&G is party to a three-year credit agreement in the amount of $200 million, which expires in October 2015. These credit agreements are used for general corporate purposes, including liquidity support for each company's commercial paper program and working capital needs and, in the case of Fuel Company, to finance or refinance the purchase of nuclear fuel, certain fossil fuels, and emission and other environmental allowances. These committed long-term facilities are revolving lines of credit under credit agreements with a syndicate of banks. Wells Fargo Bank, National Association, Bank of America, N. A. and Morgan Stanley Bank, N.A. each provide 10.7% of the aggregate $1.4 billion credit facilities, JPMorgan Chase Bank, N.A., Mizuho Corporate Bank, Ltd., TD Bank N.A., Credit Suisse AG, Cayman Islands Branch and UBS Loan Finance LLC each provide 8.9% and Branch Banking and Trust Company, Union Bank, N.A. and U.S. Bank National Association each provide 6.3%. Two other banks provide the remaining support. Consolidated SCE&G pays fees to the banks as compensation for maintaining the committed lines of credit. Such fees were not material in any period presented.

Consolidated SCE&G is obligated with respect to an aggregate of $67.8 million of industrial revenue bonds which are secured by letters of credit issued by Branch Banking and Trust Company. The letters of credit expire, subject to renewal, in the fourth quarter of 2014.

Consolidated SCE&G participates in a utility money pool. Money pool borrowings and investments bear interest at short-term market rates. Consolidated SCE&G's interest income and expense from money pool transactions was not significant for any period presented. At June 30, 2013 and December 31, 2012, Consolidated SCE&G had outstanding money pool borrowings due to an affiliate of $34.9 million and $49.4 million, respectively.

5. INCOME TAXES

No material changes in the status of Consolidated SCE&G's tax positions have occurred through June 30, 2013.

6. DERIVATIVE FINANCIAL INSTRUMENTS

Consolidated SCE&G recognizes all derivative instruments as either assets or liabilities in the statement of financial position and measures those instruments at fair value. Consolidated SCE&G recognizes changes in the fair value of derivative instruments either in earnings or within regulatory assets or regulatory liabilities, depending upon the intended use of the derivative and the resulting designation.

Policies and procedures and risk limits are established to control the level of market, credit, liquidity and operational and administrative risks assumed by Consolidated SCE&G. SCANA's Board of Directors has delegated to a Risk

Management Committee the authority to set risk limits, establish policies and procedures for risk management and measurement, and oversee and review the risk management process and infrastructure for SCANA and each of its subsidiaries, including Consolidated SCE&G. The Risk Management Committee, which is comprised of certain officers, including the Consolidated SCE&G's Risk Management Officer and senior officers, apprises the Audit Committee of the Board of Directors with regard to the management of risk and brings to the Audit Committee's attention significant areas of concern. Written policies define the physical and financial transactions that are approved, as well as the authorization requirements and limits for transactions.

Interest Rate Swaps

Consolidated SCE&G synthetically converts variable rate debt to fixed rate debt using swaps that are designated as cash flow hedges. Periodic payments to or receipts from swap counterparties related to these derivatives are recorded within interest expense.

In anticipation of the issuance of debt, Consolidated SCE&G may use treasury rate lock or forward starting swap agreements that are designated as cash flow hedges. The effective portions of changes in fair value and payments made or received upon termination of such agreements are recorded in regulatory assets or regulatory liabilities. Such amounts are amortized to interest expense over the term of the underlying debt. Ineffective portions are recognized in income. Cash payments made or received upon termination of these financial instruments are classified as investing activities for cash flow statement purposes.

Quantitative Disclosures Related to Derivatives

Consolidated SCE&G was a party to interest rate swaps designated as cash flow hedges with an aggregate notional amount of $571.4 million at June 30, 2013 and $971.4 million at December 31, 2012.

The fair value of interest rate derivatives was reflected in the condensed consolidated balance sheet as follows:

	Fair Values of Derivative Instruments			
	Asset Derivatives		Liability Derivatives	
Millions of dollars	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
As of June 30, 2013				
Derivatives designated as hedging instruments				
Interest rate	Prepayments and other	$72	Other current liabilities	$2
	Other deferred debits and other assets	34	Other deferred credits and other liabilities	3
Total		$106		$5
As of December 31, 2012				
Derivatives designated as hedging instruments				
Interest rate	Prepayments and other	$42	Other current liabilities	$66
	Other deferred debits and other assets	31	Other deferred credits and other liabilities	9
Total		$73		$75

The effect of derivative instruments on the condensed consolidated statement of income is as follows:

Derivatives in Cash Flow Hedging Relationships	Gain Deferred in Regulatory Accounts (Effective Portion)			Loss Reclassified from Deferred Accounts into Income (Effective Portion)	
Millions of dollars	2013	2012	Location	2013	2012

Three Months Ended June 30,					
Interest rate	$61	$(2)	Interest expense	—	—
Six Months Ended June 30,					
Interest rate	$96	$28	Interest expense	$(1)	$(1)

Derivatives not designated as Hedging Instruments		Loss Recognized in Income	
Millions of dollars	Location	2013	2012
Three Months Ended June 30,			
Commodity	Gas purchased for resale	—	—
Six Months Ended June 30,			
Commodity	Gas purchased for resale	—	$(1)

Hedge Ineffectiveness

Other gains (losses) recognized in income representing ineffectiveness on interest rate hedges designated as cash flow hedges were insignificant in each of the three and six months ended June 30, 2013 and 2012, respectively.

Credit Risk Considerations

Consolidated SCE&G limits credit risk in its derivatives activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. In this regard, Consolidated SCE&G uses credit ratings provided by credit rating agencies and current market-based qualitative and quantitative data as well as financial statements, to assess the financial health of counterparties on an ongoing basis. Consolidated SCE&G uses standardized master agreements which may include collateral requirements. These master agreements permit the netting of cash flows associated with a single counterparty. Cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. The collateral agreements permit the secured party to demand the posting of cash or letters of credit in the event an exposure exceeds the established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with Consolidated SCE&G's credit policies and due diligence. In addition, collateral agreements allow for the termination and liquidation of all positions in the event of a failure or inability to post collateral.

Certain of Consolidated SCE&G’s derivative instruments contain contingent provisions that may require Consolidated SCE&G to provide collateral upon the occurrence of specific events, primarily credit downgrades. As of June 30, 2013 and December 31, 2012, Consolidated SCE&G has posted $4.1 million and $35.2 million, respectively, of collateral related to derivatives with contingent provisions that were in a net liability position. Collateral related to the positions expected to close in the next 12 months are recorded in Prepayments and other on the consolidated balance sheets. Collateral related to the noncurrent positions is recorded in Other within Deferred Debits and Other Assets on the consolidated balance sheets. If all of the contingent features underlying these instruments had been fully triggered as of June 30, 2013 and December 31, 2012, Consolidated SCE&G could have been required to post an additional $0.1 million and $22.7 million respectively, of collateral with its counterparties. The aggregate fair value of all derivative instruments with contingent provisions that are in a net liability position as of June 30, 2013 and December 31, 2012 is $4.2 million and $57.9 million, respectively.

In addition, as of June 30, 2013 and December 31, 2012, Consolidated SCE&G has collected no cash collateral related to interest rate derivatives with contingent provisions that are in a net asset position. If all the contingent features underlying these instruments were fully triggered as of June 30, 2013 and December 31, 2012, Consolidated SCE&G could request $67.7 million and $32.1 million, respectively, of cash collateral from its counterparties. The aggregate fair value of all derivative instruments with contingent provisions that are in a net asset position as of June 30, 2013 and December 31, 2012 is $67.7 million and $32.1 million, respectively.

Information related to Consolidated SCE&G's derivative assets follows:

Millions of dollars	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Statement of Financial Position	Net Amounts Presented in the Statement of Financial Position	Gross Amounts Not Offset in the Statement of Financial Position		
				Financial Instruments	Cash Collateral Received	Net Amount
As of June 30, 2013						
Interest rate	$106	—	$106	$(5)	—	$101
Balance Sheet Location	Prepayments and other		$72			
	Other deferred debits and other assets		34			
	Total		$106			
As of December 31, 2012						
Interest rate	$73	—	$73	$(17)	—	$56
Balance Sheet Location	Prepayments and other		$42			
	Other deferred debits and other assets		31			
	Total		$73			

Information related to Consolidated SCE&G's derivative liabilities follows:

Millions of dollars	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Statement of Financial Position	Net Amounts Presented in the Statement of Financial Position	Gross Amounts Not Offset in the Statement of Financial Position		
				Financial Instruments	Cash Collateral Posted	Net Amount
As of June 30, 2013						
Interest rate	$5	—	$5	$(5)	$—	$—
Balance Sheet Location	Other current liabilities		$2			
	Other deferred credits and other liabilities		3			
	Total		$5			
As of December 31, 2012						
Interest rate	$75	—	$75	$(17)	$(35)	$23
Balance Sheet Location	Other current liabilities		$66			
	Other deferred credits and other liabilities		9			
	Total		$75			

7. FAIR VALUE MEASUREMENTS, INCLUDING DERIVATIVES

Consolidated SCE&G's interest rate swap agreements are valued using discounted cash flow models with independently sourced data. Fair value measurements based on significant other observable inputs (level 2) were as follows:

		Fair Value Measurements Using Significant Other Observable Inputs (Level 2)	
Millions of dollars		June 30, 2013	December 31, 2012
Assets -	Interest rate contracts	$106	$73
Liabilities -	Interest rate contracts	5	75

There were no fair value measurements based on quoted prices in active markets for identical assets (Level 1) or significant unobservable inputs (Level 3) for either period presented. In addition, there were no transfers of fair value amounts into or out of Levels 1, 2 or 3 during the periods presented.

Financial instruments for which the carrying amount may not equal estimated fair value at June 30, 2013 and December 31, 2012 were as follows:

Millions of dollars	June 30, 2013 Carrying Amount	June 30, 2013 Estimated Fair Value	December 31, 2012 Carrying Amount	December 31, 2012 Estimated Fair Value
Long-term debt	$4,058.5	$4,447.4	$3,722.0	$4,543.1

Fair values of long-term debt instruments are based on net present value calculations using independently sourced market data that incorporate a developed discount rate using similarly rated long-term debt, along with benchmark interest rates. As such, the aggregate fair values presented above are considered to be Level 2. Early settlement of long-term debt may not be possible or may not be considered prudent.

Carrying values of short-term borrowings approximate fair value, and are based on quoted prices from dealers in the commercial paper market. The resulting fair value is considered to be Level 2.

8. EMPLOYEE BENEFIT PLANS

Pension and Other Postretirement Benefit Plans

Consolidated SCE&G participates in SCANA's noncontributory defined benefit pension plan, which covers substantially all regular, full-time employees, and also participates in SCANA's unfunded postretirement health care and life insurance programs, which provide benefits to active and retired employees. Components of net periodic benefit cost recorded by Consolidated SCE&G were as follows:

	Pension Benefits		Other Postretirement Benefits	
Millions of dollars	2013	2012	2013	2012
Three months ended June 30,				
Service cost	$4.8	$3.8	$1.3	$1.0
Interest cost	8.0	9.1	2.2	2.3
Expected return on assets	(13.0)	(12.6)	—	—
Prior service cost amortization	1.4	1.5	0.1	0.2
Amortization of actuarial losses	4.6	4.0	0.7	0.1
Net periodic benefit cost	$5.8	$5.8	$4.3	$3.6

	Pension Benefits		Other Postretirement Benefits	
Millions of dollars	2013	2012	2013	2012
Six months ended June 30,				
Service cost	$9.6	$7.7	$2.5	$2.0
Interest cost	16.0	18.2	4.4	4.7
Expected return on assets	(26.0)	(25.2)	—	—
Prior service cost amortization	2.8	2.9	0.3	0.4
Amortization of actuarial losses	9.2	8.0	1.3	0.2
Net periodic benefit cost	$11.6	$11.6	$8.5	$7.3

No contribution to the pension trust will be necessary until after 2014, nor will limitations on benefit payments apply. As authorized by the SCPSC, prior to January 1, 2013 SCE&G deferred all pension expense related to retail electric and gas operations as a regulatory asset. In connection with the SCPSC's December 2012 rate order, effective January 1, 2013 SCE&G began recovering pension expense related to retail electric operations through a rate rider that is adjusted annually. SCE&G continues to defer such costs related to gas operations. Costs totaling $0.6 million and $1.2 million related to gas operations were deferred for the three and six months ended June 30, 2013, respectively. Costs totaling $3.7 million and $7.4 million related to electric and gas operations were deferred for the corresponding periods in 2012. Previously deferred cost related to electric operations are being recovered as described in Note 2.

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9. COMMITMENTS AND CONTINGENCIES

Nuclear Insurance

Under Price-Anderson, SCE&G (for itself and on behalf of Santee Cooper, a one-third owner of Summer Station Unit 1) maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at the Company's nuclear power plant. Price-Anderson provides funds up to $12.6 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $375 million by ANI with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. Each reactor licensee is currently liable for up to $117.5 million per reactor owned for each nuclear incident occurring at any reactor in the United States, provided that not more than $17.5 million of the liability per reactor would be assessed per year. SCE&G’s maximum assessment, based on its two-thirds ownership of Summer Station Unit 1, would be $78.3 million per incident, but not more than $11.7 million per year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years.

SCE&G currently maintains insurance policies (for itself and on behalf of Santee Cooper) with NEIL. The policies provide coverage to Summer Station Unit 1 for property damage and outage costs up to $2.75 billion. In addition, a builder's risk insurance policy has been purchased from NEIL for the construction of the New Units. This policy provides the owners of the New Units up to $500 million in limits of accidental property damage occurring during construction. The NEIL policies, in the aggregate, are subject to a maximum loss of $2.75 billion for any single loss occurrence. All of the NEIL policies permit retrospective assessments under certain conditions to cover insurer’s losses. Based on the current annual premium, SCE&G’s portion of the retrospective premium assessment would not exceed $40.6 million.

To the extent that insurable claims for property damage, decontamination, repair and replacement and other costs and expenses arising from a nuclear incident at Summer Station Unit 1 exceed the policy limits of insurance, or to the extent such insurance becomes unavailable in the future, and to the extent that SCE&G's rates would not recover the cost of any purchased replacement power or other cost and expenses, SCE&G will retain the risk of loss as a self-insurer. SCE&G has no reason to anticipate a serious nuclear incident. However, if such an incident were to occur, it likely would have a material impact on the Company’s results of operations, cash flows and financial position.

Environmental

On April 13, 2012, the EPA issued a proposed rule to establish NSPS for GHG emissions from fossil fuel-fired electric generating units. If finalized as proposed, this rule would establish performance standards for new and modified generating units, along with emissions guidelines for existing generating units. This rule would amend the NSPS for electric generating units and establish the first NSPS for GHG emissions. Essentially, the rule would require all new fossil fuel-fired power plants to meet the carbon dioxide emissions profile of a combined cycle natural gas plant. While most new natural gas plants will not be required to include any new technologies, no new coal plants could be constructed without carbon capture and sequestration capabilities. As part of the President's Climate Action Plan and by Presidential Memorandum issued June 25, 2013, the EPA was directed to issue a revised carbon standard for new power plants by September 20, 2013, to be made final as soon as appropriate. Standards, regulations, or guidelines are also required for existing units by June 1, 2014, to be made final no later than June 1, 2015. Consolidated SCE&G is evaluating the proposed rule, but cannot predict when the rule will become final, if at all, or what conditions it may impose on Consolidated SCE&G, if any. Consolidated SCE&G expects that any costs incurred to comply with GHG emission requirements will be recoverable through rates.

In 2005, the EPA issued the CAIR, which required the District of Columbia and 28 states, including South Carolina, to reduce nitrogen oxide and sulfur dioxide emissions in order to attain mandated state levels. CAIR set emission limits to be met in two phases beginning in 2009 and 2015, respectively, for nitrogen oxide and beginning in 2010 and 2015, respectively, for sulfur dioxide. SCE&G and GENCO determined that additional air quality controls would be needed to meet the CAIR requirements. On July 6, 2011 the EPA issued the CSAPR. This rule replaced CAIR and the Clean Air Transport Rule proposed in July 2010 and is aimed at addressing power plant emissions that may contribute to air pollution in other states. CSAPR requires states in the eastern United States to reduce power plant emissions, specifically sulfur dioxide and nitrogen oxide. On December 30, 2011, the United States Court of Appeals for the District of Columbia issued an order staying CSAPR and reinstating CAIR pending resolution of an appeal of CSAPR. On August 21, 2012, the Court of Appeals vacated CSAPR and left CAIR in place. The EPA's petition for rehearing of the Court of Appeals' order has been denied. On March 29, 2013, the U.S. Solicitor General petitioned the U. S. Supreme Court to review the D.C. Circuit Court's decision on CSAPR. On June 24, 2013, the U.S. Supreme Court agreed to review the lower court's decision. Air quality control installations that SCE&G and

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GENCO have already completed have allowed the Consolidated SCE&G to comply with the reinstated CAIR. Consolidated SCE&G will continue to pursue strategies to comply with all applicable environmental regulations. Any costs incurred to comply with such regulations are expected to be recoverable through rates.

In April 2012, the EPA's rule containing new standards for mercury and other specified air pollutants became effective. The rule provides up to four years for facilities to meet the standards, and Consolidated SCE&G's evaluation of the rule is ongoing. Consolidated SCE&G's decision in 2012 to retire certain coal-fired units or convert them to burn natural gas and its project to build the New Units (see Note 1) along with other actions are expected to result in Consolidated SCE&G's compliance with the EPA's rule. Any costs incurred to comply with this rule or other rules issued by the EPA in the future are expected to be recoverable through rates.

The EPA is conducting an enforcement initiative against the utilities industry related to the NSR provisions and the NSPS of the CAA. As part of the initiative, many utilities have received requests for information under Section 114 of the CAA. In addition, the DOJ, on behalf of the EPA, has taken civil enforcement action against several utilities. The primary basis for these actions is the assertion by the EPA that maintenance activities undertaken by the utilities at their coal-fired power plants constituted “major modifications” which required the installation of costly BACT. Some of the utilities subject to the actions have reached settlement. Though Consolidated SCE&G cannot predict what action, if any, the EPA will initiate against it, any costs incurred are expected to be recoverable through rates.

Consolidated SCE&G maintains an environmental assessment program to identify and evaluate its current and former operations sites that could require environmental clean-up. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. Environmental liabilities are accrued when the criteria for loss contingencies are met. These estimates are refined as additional information becomes available; therefore, actual expenditures could differ significantly from the original estimates. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Amounts expected to be recovered through rates are recorded in regulatory assets and, if applicable, amortized over approved amortization periods. Other environmental costs are recorded to expense.

SCE&G is responsible for four decommissioned MGP sites in South Carolina which contain residues of byproduct chemicals. These sites are in various stages of investigation, remediation and monitoring under work plans approved by DHEC and the EPA. SCE&G anticipates that major remediation activities at all these sites will continue until 2016 and will cost an additional $21.9 million, which is accrued in Other within Deferred Credits and Other Liabilities on the condensed consolidated balance sheet. SCE&G expects to recover any cost arising from the remediation of MGP sites through rates. At June 30, 2013, deferred amounts, net of amounts previously recovered through rates and insurance settlements, totaled $37.9 million and are included in regulatory assets.

New Nuclear Construction

SCE&G, on behalf of itself and as agent for Santee Cooper, has contracted with the Consortium for the design and construction of the New Units at the site of Summer Station. SCE&G's share of the estimated cash outlays (future value, excluding AFC) totals approximately $5.5 billion for plant and related transmission infrastructure costs, and is projected based on historical one-year and five-year escalation rates as required by the SCPSC.

The Consortium has experienced delays in the schedule for fabrication and delivery of sub-modules for the New Units. Following an examination of this issue, the Consortium has preliminarily indicated that the substantial completion of the first New Unit is expected to be delayed until late 2017 or the first quarter of 2018 and that the substantial completion of the second New Unit is expected to be similarly delayed. The substantial completion dates currently approved by the SCPSC for the first and second New Units are March 15, 2017 and May 15, 2018, respectively. The SCPSC has also approved an 18-month contingency period beyond each of these dates. The preliminary expected new substantial completion dates are within the contingency periods. SCE&G cannot predict with certainty the extent to which the issue with the sub-modules or the delays in the substantial completion of the New Units will result in increased project costs. However, the preliminary estimate of the delay-related costs associated with SCE&G's share of the New Units is approximately $200 million. SCE&G intends to continue to work with the Consortium to refine this preliminary estimate and expects to have further discussions with the Consortium regarding responsibility for these increased costs.

In addition to the above-described project delays, SCE&G has also become aware of recent press reports concerning financial difficulties at a supplier responsible for certain significant components of the project. SCE&G has asked the Consortium to evaluate the potential for disruptions in such equipment fabrication and possible responses. Any disruptions could impact the project's schedule or costs, and such impacts could be material.

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The parties to the EPC Contract have established both informal and formal dispute resolution procedures in order to resolve issues that arise during the course of constructing a project of this magnitude. During the course of activities under the EPC Contract, issues have materialized that impact project budget and schedule. Claims specifically relating to COL delays,
design modifications of the shield building and certain pre-fabricated modules for the New Units and unanticipated rock
conditions at the site resulted in assertions of contractual entitlement to recover additional costs to be incurred. The resolution
of these specific claims is discussed in Note 2. SCE&G expects to resolve any disputes that arise in the future, including any which may arise with respect to the delay-related costs discussed above, through both the informal and formal procedures and anticipates that any additional costs that arise through such dispute resolution processes, as well as other costs identified from time to time, will be recoverable through rates.

When the NRC issued the COLs for the New Units, two of the conditions that it imposed were requiring inspection and testing of certain components of the New Units' passive cooling system, and requiring the development of strategies to respond to extreme natural events resulting in the loss of power at the New Units. In addition, the NRC directed the Office of New Reactors to issue to SCE&G an order requiring enhanced, reliable spent fuel pool instrumentation, as well as a request for information related to emergency plant staffing. These conditions and requirements are responsive to the NRC's Near-Term Task Force report titled “Recommendations for Enhancing Reactor Safety in the 21st Century.” This report was prepared in the wake of the March 2011 earthquake-generated tsunami, which severely damaged several nuclear generating units and their back-up cooling systems in Japan. SCE&G continues to evaluate the impact of these conditions and requirements that may be imposed on the construction and operation of the New Units, and SCE&G is preparing an integrated response plan for the New Units, which it expects to submit to the NRC in August 2013. SCE&G cannot predict what additional regulatory or other outcomes may be implemented in the United States, or how such initiatives would impact SCE&G's existing Summer Station or the construction or operation of the New Units.

As previously reported, SCE&G has been advised by Santee Cooper that it is reviewing certain aspects of its capital improvement program and long-term power supply plan, including the level of its participation in the New Units. SCE&G is unable to predict whether any change in Santee Cooper's ownership interest or the addition of new joint owners will increase project costs or delay the commercial operation dates of the New Units. Any such project cost increase or delay could be material.

10. AFFILIATED TRANSACTIONS

CGT transports natural gas to SCE&G to serve SCE&G’s retail gas customers and certain electric generation requirements. Transportation services totaled approximately $16.9 million and $18.5 million for the six months ended June 30, 2013 and 2012, respectively. SCE&G had approximately $2.9 million and $3.4 million payable to CGT for transportation services at June 30, 2013 and December 31, 2012, respectively.

SCE&G purchases natural gas and related pipeline capacity from SEMI to serve its retail gas customers and certain electric generation requirements. Such purchases totaled approximately $89.3 million and $48.8 million for the six months ended June 30, 2013 and 2012, respectively. SCE&G’s payables to SEMI for such purposes were $14.8 million and $13.1 million as of June 30, 2013 and December 31, 2012, respectively.

SCE&G owns 40% of Canadys Refined Coal, LLC, which is involved in the manufacturing and sale of refined coal to reduce emissions. SCE&G owned 10% of Cope Refined Coal, LLC through December 31, 2012. SCE&G accounts for these investments using the equity method. SCE&G’s receivables from these affiliates were $11.5 million at June 30, 2013 and $1.8 million at December 31, 2012. SCE&G’s payables to these affiliates were $11.6 million at June 30, 2013 and $1.8 million at December 31, 2012. SCE&G's total purchases from these affiliates were $31.8 million and $46.9 million for the six months ended June 30, 2013 and 2012, respectively. SCE&G's total sales to these affiliates were $31.6 million and $46.6 million for the six months ended June 30, 2013 and 2012, respectively.

Consolidated SCE&G receives the following services from SCANA Services and its parent company, which are rendered at direct or allocated cost: information systems services, customer services, marketing and sales, human resources, corporate compliance, purchasing, financial services, risk management, public affairs, legal services, investor relations, gas supply and capacity management, strategic planning, general administrative services, and retirement benefits. Consolidated SCE&G's payables for such purposes were $39.6 million and $45.8 million as of June 30, 2013 and December 31, 2012, respectively.
Money pool borrowings from an affiliate are described at Note 4.

11. SEGMENT OF BUSINESS INFORMATION

Consolidated SCE&G's reportable segments are listed in the following table. Consolidated SCE&G uses operating income to measure profitability for its regulated operations. Therefore, earnings available to common shareholder are not allocated to the Electric Operations and Gas Distribution segments. Intersegment revenues were not significant.

Millions of dollars	External Revenue	Operating Income	Earnings Available to Common Shareholder
Three Months Ended June 30, 2013			
Electric Operations	$612	$178	n/a
Gas Distribution	84	2	n/a
Adjustments/Eliminations	—	—	$85
Consolidated Total	$696	$180	$85
Six Months Ended June 30, 2013			
Electric Operations	$1,197	$331	n/a
Gas Distribution	227	40	n/a
Adjustments/Eliminations	—	—	$174
Consolidated Total	$1,424	$371	$174
Three Months Ended June 30, 2012			
Electric Operations	$594	$163	n/a
Gas Distribution	67	2	n/a
Adjustments/Eliminations	—	—	$76
Consolidated Total	$661	$165	$76
Six Months Ended June 30, 2012			
Electric Operations	$1,141	$290	n/a
Gas Distribution	183	31	n/a
Adjustments/Eliminations	—	—	$143
Consolidated Total	$1,324	$321	$143

Segment Assets	June 30, 2013	December 31, 2012
Electric Operations	$9,272	$8,989
Gas Distribution	673	659
Adjustments/Eliminations	2,587	2,456
Consolidated Total	$12,532	$12,104

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ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

SOUTH CAROLINA ELECTRIC & GAS COMPANY

The following discussion should be read in conjunction with Management's Discussion and Analysis of Financial Condition and Results of Operations appearing in SCE&G's Annual Report on Form 10-K for the year ended December 31, 2012.

RESULTS OF OPERATIONS
FOR THE THREE AND SIX MONTHS ENDED JUNE 30, 2013
AS COMPARED TO THE CORRESPONDING PERIODS IN 2012

Net Income

Net income for Consolidated SCE&G was as follows:

	Second Quarter			Year to Date		
Millions of dollars	2013	Change	2012	2013	Change	2012
Net income	$88.0	13.3 %	$77.7	$179.8	20.5 %	$149.2

Second Quarter

Net income increased due to higher electric margin from base rate increases. This margin increase was partially offset by higher operation and maintenance expenses, higher depreciation expense and higher property taxes as further described below.

Year to Date

Net income increased due to higher electric margin and higher gas margin. These margin increases were partially offset by higher operation and maintenance expenses, higher depreciation expense, higher property taxes and higher interest expense as further described below.

Dividends Declared

Consolidated SCE&G's Boards of Directors declared the following dividends on common stock (all of which was held by SCANA) during 2013:

Declaration Date	Amount	Quarter Ended	Payment Date
February 20, 2013	$64.0 million	March 31, 2013	April 1, 2013
April 25, 2013	$63.8 million	June 30, 2013	July 1, 2013
July 31, 2013	$67.5 million	September 30, 2013	October 1, 2013

Electric Operations

Electric Operations is comprised of the electric operations of SCE&G, GENCO and Fuel Company. Electric operations sales margin (including transactions with affiliates) was as follows:

	Second Quarter			Year to Date		
Millions of dollars	2013	Change	2012	2013	Change	2012
Operating revenues	$611.6	2.9 %	$594.1	$1,197.2	4.9 %	$1,141.4
Less: Fuel used in generation	189.2	(5.0)%	199.2	376.9	(1.3)%	381.9

Purchased power	8.8	91.3	%	4.6	15.8	53.4	%	10.3
Margin	$413.6	6.0	%	$390.3	$804.5	7.4	%	$749.2

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Second Quarter

Electric margin increased primarily due to base rate increases under the BLRA of $12.1 million and higher retail electric base rates of $15.1 million approved in the December 2012 rate order.

Year to Date

Electric margin increased primarily due to base rate increases under the BLRA of $25.1 million and higher retail electric base rates of $32.0 million approved in the December 2012 rate order.

Sales volumes (in GWh) related to the electric margin above, by class, were as follows:

	Second Quarter				Year to Date			
Classification	2013	Change		2012	2013	Change		2012
Residential	1,784	(0.8	)%	1,799	3,642	4.4	%	3,490
Commercial	1,777	(3.7	)%	1,846	3,446	(1.3	)%	3,490
Industrial	1,518	0.3	%	1,514	2,921	0.8	%	2,899
Other	144	(2.0	)%	147	279	(1.1	)%	282
Total Retail Sales	5,223	(1.6	)%	5,306	10,288	1.2	%	10,161
Wholesale	228	(63.4	)%	623	491	(60.9	)%	1,257
Total Sales	5,451	(8.1	)%	5,929	10,779	(5.6	)%	11,418

Second Quarter

Retail sales volume decreased primarily due to lower average use, partially offset by customer growth. The decrease in wholesale sales is primarily due to the expiration of two customer contracts.

Year to Date

Retail sales volume increased primarily due to the effects of customer growth and weather. The decrease in wholesale sales is primarily due to the expiration of two customer contracts.

Gas Distribution

Gas Distribution is comprised of the local distribution operations of SCE&G. Gas distribution sales margin (including transactions with affiliates) was as follows:

	Second Quarter				Year to Date			
Millions of dollars	2013	Change		2012	2013	Change		2012
Operating revenues	$ 84.2	26.0	%	$ 66.8	$ 226.9	24.3	%	$ 182.5
Less: Gas purchased for resale	54.6	47.2	%	37.1	131.7	36.8	%	96.3
Margin	$ 29.6	(0.3	)%	$ 29.7	$ 95.2	10.4	%	$ 86.2

Year to Date

Margin increased primarily due to the SCPSC-approved increase in base rates under the RSA which became effective with the first billing cycle of November 2012.

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Sales volumes (in MMBTU) by class, including transportation, were as follows:

	Second Quarter			Year to Date		
Classification (in thousands)	2013	Change	2012	2013	Change	2012
Residential	1,261	41.4 %	892	7,719	40.1 %	5,511
Commercial	2,644	7.3 %	2,463	6,938	14.8 %	6,042
Industrial	5,081	9.9 %	4,625	10,450	10.4 %	9,467
Transportation	1,132	1.9 %	1,111	2,449	1.4 %	2,416
Total	10,118	11.3 %	9,091	27,556	17.6 %	23,436

Second Quarter and Year to Date

Total sales volumes increased primarily due to the effects of weather.

Other Operating Expenses

Other operating expenses were as follows:

	Second Quarter			Year to Date		
Millions of dollars	2013	Change	2012	2013	Change	2012
Other operation and maintenance	$135.4	1.2 %	$133.8	$273.8	0.6 %	$272.1
Depreciation and amortization	78.6	6.6 %	73.7	156.2	6.4 %	146.8
Other taxes	49.5	2.9 %	48.1	99.1	3.6 %	95.7

Second Quarter

Other operation and maintenance expenses increased by $4.1 million due to incremental expenses associated with the December 2012 rate order and by $2.0 million due to higher generation expenses. These increases were partially offset by $1.0 million due to lower compensation and by other general expenses. Depreciation and amortization expense increased $3.3 million due to the recognition of depreciation expense associated with the Wateree Station scrubber which was provided for in the December 2012 rate order and due to net plant additions. Other taxes increased primarily due to higher property taxes.

Year to Date

Other operation and maintenance expenses increased by $8.2 million due to incremental expenses associated with the December 2012 rate order. These increases were partially offset by $1.5 million due to lower generation expenses, by $2.7 million due to lower compensation and by other general expenses. Depreciation and amortization expense increased $6.6 million due to the recognition of depreciation expense associated with the Wateree Station scrubber which was provided for in the December 2012 rate order and due to net plant additions. Other taxes increased primarily due to higher property taxes.

Other Expense

Other income (expense) includes the results of certain incidental (non-utility) activities and AFC. AFC is a utility accounting practice whereby a portion of the cost of both equity and borrowed funds used to finance construction (which is shown on the balance sheet as construction work in progress) is capitalized. Consolidated SCE&G includes an equity portion of AFC in nonoperating income and a debt portion of AFC in interest charges (credits), both of which have the effect of increasing reported net income.

Interest Expense

Interest charges increased primarily due to increased borrowings.

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Income Taxes

Income taxes for the three and six months ended June 30, 2013 were higher than the same periods in 2012 primarily due to higher income. The increase in the effective tax rate for year to date 2013 is principally attributable to lower recognition of EIZ Credits upon the completion of amortization of certain such credits in 2012.

LIQUIDITY AND CAPITAL RESOURCES

Consolidated SCE&G anticipates that its contractual cash obligations will be met through internally generated funds, the incurrence of additional short- and long-term indebtedness, and equity contributions from its parent company. Consolidated SCE&G expects that, barring a future impairment of the capital markets, it has or can obtain adequate sources of financing to meet its projected cash requirements for the foreseeable future, including the cash requirements for nuclear construction and refinancing maturing long-term debt. Consolidated SCE&G's ratio of earnings to fixed charges for the six and 12 months ended June 30, 2013 was 3.30 and 3.42, respectively.

SCE&G received approximately $255 million during the six months ended June 30, 2013 as an equity contribution from its parent company.

Consolidated SCE&G is obligated with respect to an aggregate of $67.8 million of industrial revenue bonds which are secured by letters of credit issued by Branch Banking and Trust Company. These letters of credit expire, subject to renewal, in the fourth quarter of 2014.

At June 30, 2013, Consolidated SCE&G had net available liquidity of approximately $1.2 billion. Consolidated SCE&G's credit agreements total an aggregate of $1.4 billion, of which $200 million is scheduled to expire in October 2015 and the remainder is scheduled to expire in October 2017. Consolidated SCE&G regularly monitors the commercial paper and short-term credit markets to optimize the timing of repayment of outstanding balances on its draws, if any, from the credit facilities. Consolidated SCE&G's long term debt portfolio has a weighted average maturity of approximately 20 years and bears an average interest cost of 5.7%. Substantially all of the long-term debt bears fixed interest rates or is swapped to fixed. To further preserve liquidity, Consolidated SCE&G rigorously reviews its projected capital expenditures and operating costs and adjusts them where possible without impacting safety, reliability, and core customer service.

SCE&G has obtained FERC authority to issue short-term indebtedness and to assume liabilities as a guarantor (pursuant to Section 204 of the Federal Power Act). SCE&G may issue unsecured promissory notes, commercial paper and direct loans in amounts not to exceed $1.6 billion outstanding with maturity dates of one year or less, and may enter into guaranty agreements in favor of lenders, bankers, and dealers in commercial paper in amounts not to exceed $600 million. GENCO has obtained FERC authority to issue short-term indebtedness not to exceed $150 million outstanding with maturity dates of one year or less. The authority described herein will expire in October 2014.

On May 28, 2013, Standard & Poor's Ratings Services revised the rating outlook of SCE&G to "negative" from "stable" but affirmed SCE&G's corporate credit rating.

In connection with the expected delays in the substantial completion of the New Units described in Note 9 to the condensed consolidated financial statements, SCE&G's current preliminary estimates of its capital expenditures for new nuclear construction (including transmission) for 2013 through 2015, which are subject to continuing review and adjustment, are $740 million in 2013, $979 million in 2014, and $881 million in 2015.

OTHER MATTERS

For information related to environmental matters, nuclear generation, and claims and litigation, see Note 9 to the condensed consolidated financial statements.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Interest Rate Risk - Consolidated SCE&G's market risk exposures relative to interest rate risk have not changed materially compared with SCE&G's Annual Report on Form 10-K for the year ended December 31, 2012. Interest rates on substantially all of Consolidated SCE&G's outstanding long-term debt, other than credit facility draws, are fixed either through the issuance of fixed rate debt or through the use of interest rate derivatives. Consolidated SCE&G is not aware of any facts or circumstances that would significantly affect exposures on existing indebtedness in the near future.

For further discussion of changes in long-term debt and interest rate derivatives, see ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - LIQUIDITY AND CAPITAL RESOURCES and also Notes 4 and 6 of the condensed consolidated financial statements.

ITEM 4. CONTROLS AND PROCEDURES

As of June 30, 2013, SCE&G conducted an evaluation under the supervision and with the participation of its management, including its CEO and CFO, of (a) the effectiveness of the design and operation of its disclosure controls and procedures and (b) any change in its internal control over financial reporting. Based on this evaluation, the CEO and CFO concluded that, as of June 30, 2013, SCE&G's disclosure controls and procedures were effective. There has been no change in SCE&G's internal control over financial reporting during the quarter ended June 30, 2013, that has materially affected or is reasonably likely to materially affect SCE&G's internal control over financial reporting.

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PART II. OTHER INFORMATION

ITEM 6. EXHIBITS

SCANA and SCE&G:

Exhibits filed or furnished with this Quarterly Report on Form 10-Q are listed in the following Exhibit Index.

As permitted under Item 601(b) (4) (iii) of Regulation S-K, instruments defining the rights of holders of long-term debt of less than 10 percent of the total consolidated assets of SCANA, for itself and its subsidiaries, and of SCE&G, for itself and its consolidated affiliates, have been omitted and SCANA and SCE&G agree to furnish a copy of such instruments to the SEC upon request.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, each of the registrants has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of each registrant shall be deemed to relate only to matters having reference to such registrant and any subsidiaries thereof.

SCANA CORPORATION
SOUTH CAROLINA ELECTRIC & GAS COMPANY
(Registrants)

	By:	/s/James E. Swan, IV
Date: August 8, 2013		James E. Swan, IV
		Controller
		(Principal accounting officer)

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EXHIBIT INDEX

Exhibit No.	Applicable to Form 10-Q of SCANA	SCE&G	Description
3.01	X		Restated Articles of Incorporation of SCANA, as adopted on April 26, 1989 (Filed as Exhibit 3-A to Registration Statement No. 33-49145 and incorporated by reference herein)
3.02	X		Articles of Amendment dated April 27, 1995 (Filed as Exhibit 4-B to Registration Statement No. 33-62421 and incorporated by reference herein)
3.03	X		Articles of Amendment effective April 25, 2011 (Filed as Exhibit 4.03 to Registration Statement No. 333-174796 and incorporated by reference herein)
3.04		X	Restated Articles of Incorporation of SCE&G, as adopted on December 30, 2009 (Filed as Exhibit 1 to Form 8-A (File Number 000-53860) and incorporated by reference herein)
3.05	X		By-Laws of SCANA as amended and restated as of February 19, 2009 (Filed as Exhibit 4.04 to Registration Statement No. 333-174796 and incorporated by reference herein)
3.06		X	By-Laws of SCE&G as revised and amended on February 22, 2001 (Filed as Exhibit 3.05 to Registration Statement No. 333-65460 and incorporated by reference herein)
31.01	X		Certification of Principal Executive Officer Required by Rule 13a-14 (Filed herewith)
31.02	X		Certification of Principal Financial Officer Required by Rule 13a-14 (Filed herewith)
31.03		X	Certification of Principal Executive Officer Required by Rule 13a-14 (Filed herewith)
31.04		X	Certification of Principal Financial Officer Required by Rule 13a-14 (Filed herewith)
32.01	X		Certification of Principal Executive Officer Pursuant to 18 U.S.C. Section 1350 (Furnished herewith)
32.02	X		Certification of Principal Financial Officer Pursuant to 18 U.S.C. Section 1350 (Furnished herewith)
32.03		X	Certification of Principal Executive Officer Pursuant to 18 U.S.C. Section 1350 (Furnished herewith)
32.04		X	

			Certification of Principal Financial Officer Pursuant to 18 U.S.C. Section 1350 (Furnished herewith)
101. INS*	X	X	XBRL Instance Document
101. SCH*	X	X	XBRL Taxonomy Extension Schema
101. CAL*	X	X	XBRL Taxonomy Extension Calculation Linkbase
101. DEF*	X	X	XBRL Taxonomy Extension Definition Linkbase
101. LAB*	X	X	XBRL Taxonomy Extension Label Linkbase
101. PRE*	X	X	XBRL Taxonomy Extension Presentation Linkbase

* Pursuant to Rule 406T of Regulation S-T, this interactive data file is deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, is deemed not filed for purposes of Section 18 of the Securities Exchange Act of 1934, and otherwise is not subject to liability under these sections.