SCANA CORP
Form 10-Q
August 07, 2015
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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, 2015

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)	57-0784499
1-3375	South Carolina Electric & Gas Company (a South Carolina corporation)	57-0248695
	100 SCANA Parkway, Cayce, South Carolina 29033	
	(803) 217-9000	

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 o South Carolina Electric & Gas Company Yes x No o

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 o South Carolina Electric & Gas Company Yes x No o

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 the 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	Accelerated filer o	Non-accelerated filer o
	Smaller reporting company o		
South Carolina Electric & Gas Company	Large accelerated filer o	Accelerated filer o	Non-accelerated filer x
	Smaller reporting company o		

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). SCANA Corporation Yes o No x South Carolina Electric & Gas Company Yes o 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, 2015
SCANA Corporation	Without Par Value	142,916,917
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) legislative and regulatory actions, particularly changes in rate regulation, regulations governing electric grid reliability and pipeline integrity, 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) the loss of sales to distributed generation, such as solar photovoltaic systems;
(8) growth opportunities for SCANA’s regulated and diversified subsidiaries;
(9) the results of short- and long-term financing efforts, including prospects for obtaining access to capital markets and other sources of liquidity;
(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) changes in SCANA’s or its subsidiaries’ accounting rules and accounting policies;
(12) payment and performance by counterparties and customers as contracted and when due;
(13) the results of efforts to license, site, construct and finance facilities for electric generation and transmission, including nuclear generating facilities, and the results of efforts to operate its electric and gas systems and assets in accordance with acceptable performance standards;
(14) maintaining creditworthy joint owners for SCE&G’s new nuclear generation project;
(15) the ability of suppliers, both domestic and international, to timely provide the labor, secure processes, components, parts, tools, equipment and other supplies needed, at agreed upon quality and prices, for our construction program, operations and maintenance;
(16) the results of efforts to ensure the physical and cyber security of key assets and processes;
(17) 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;
(18) the availability of skilled and experienced human resources to properly manage, operate, and grow the Company’s businesses;

(19) labor disputes;
(20) performance of SCANA's pension plan assets;
(21) changes in taxes and tax credits, including production tax credits for new nuclear units;
(22) inflation or deflation;
(23) compliance with regulations;
(24) natural disasters and man-made mishaps that directly affect our operations or the regulations governing them; and
(25) the other risks and uncertainties described from time to time in the 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
BLRA	Base Load Review Act
CAA	Clean Air Act, as amended
CAIR	Clean Air Interstate Rule
CCR	Coal Combustion Residuals
CEO	Chief Executive Officer
CFO	Chief Financial Officer
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act
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 CB&I Stone and Webster, Inc., a subsidiary of Chicago Bridge & Iron Company N.V.
Court of Appeals	United States Court of Appeals for the District of Columbia
CSAPR	Cross-State Air Pollution Rule
CUT	Customer Usage Tracker
CWA	Clean Water Act
DER	Distributed Energy Resource
DHEC	South Carolina Department of Health and Environmental Control
DOE	United States Department of Energy
DSM Programs	Demand reduction and energy efficiency programs
ELG Rule	New federal effluent limitation guidelines for steam electric generating units
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
FASB	Financial Accounting Standards Board
FERC	United States Federal Energy Regulatory Commission
Fuel Company	South Carolina Fuel Company, Inc.
GAAP	Accounting principles generally accepted in the United States of America
GENCO	South Carolina Generating Company, Inc.
GHG	Greenhouse Gas
GPSC	Georgia Public Service Commission
GWh	Gigawatt hour
IRP	Integrated Resource Plan
IRS	Internal Revenue Service
Level 1	A fair value measurement using unadjusted quoted prices in active markets for identical assets or liabilities
Level 2	A fair value measurement using observable inputs other than those for Level 1, including quoted prices for similar (not identical) assets or liabilities or inputs that are derived from observable market data by correlation or other means

Level 3	A fair value measurement using unobservable inputs, including situations where there is little, if any, market activity for the asset or liability
LOC	Lines of Credit

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MATS	Mercury and Air Toxics Standards
MGP	Manufactured Gas Plant
MMBTU	Million British Thermal Units
MW or MWh	Megawatt or Megawatt-hour
NAAQS	National Ambient Air Quality Standards
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
NPDES	National Permit Discharge Elimination System
NRC	United States Nuclear Regulatory Commission
NSPS	New Source Performance Standards
Nuclear Waste Act	Nuclear Waste Policy Act of 1982
NYMEX	New York Mercantile Exchange
OCI	Other Comprehensive Income
ORS	South Carolina Office of Regulatory Staff
PGA	Purchased Gas Adjustment
Price-Anderson	Price-Anderson Indemnification Act
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
SCI	SCANA Communications, Inc.
SCPSC	Public Service Commission of South Carolina
SEC	United States Securities and Exchange Commission
SEMI	SCANA Energy Marketing, Inc.
Spirit Communications	SCTG Communications, Inc. (a wholly owned subsidiary of SCTG, LLC) d/b/a Spirit Communications
Summer Station	V. C. Summer Nuclear Station
VIE	Variable Interest Entity

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PART I. FINANCIAL INFORMATION

SCANA CORPORATION FINANCIAL SECTION
ITEM 1. F INANCIAL STATEMENTS

SCANA CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

Millions of dollars	June 30, 2015	December 31, 2014
Assets		
Utility Plant In Service	$12,392	$12,289
Accumulated Depreciation and Amortization	(4,110)	(4,088)
Construction Work in Progress	3,621	3,323
Plant to be Retired, Net	162	169
Nuclear Fuel, Net of Accumulated Amortization	316	329
Goodwill, net of writedown of $230	210	210
Utility Plant, Net	12,591	12,232
Nonutility Property and Investments:		
Nonutility property, net of accumulated depreciation of $121 and $122	284	284
Assets held in trust, net-nuclear decommissioning	114	113
Other investments	76	75
Nonutility Property and Investments, Net	474	472
Current Assets:		
Cash and cash equivalents	55	137
Receivables, net of allowance for uncollectible accounts of $6 and $7	658	838
Inventories (at average cost):		
Fuel and gas supply	184	222
Materials and supplies	147	139
Prepayments	199	320
Other current assets	46	148
Assets held for sale	—	341
Total Current Assets	1,289	2,145
Deferred Debits and Other Assets:		
Regulatory assets	1,798	1,823
Other	216	180
Total Deferred Debits and Other Assets	2,014	2,003
Total	$16,368	$16,852

See Notes to Condensed Consolidated Financial Statements.

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Millions of dollars	June 30, 2015	December 31, 2014
Capitalization and Liabilities		
Common Stock - no par value (shares outstanding: June 30, 2015 - 142.9 million; December 31, 2014 - 142.7 million)	$2,391	$2,378
Retained Earnings	3,027	2,684
Accumulated Other Comprehensive Loss	(67)	(75)
Total Common Equity	5,351	4,987
Long-Term Debt, net	6,018	5,531
Total Capitalization	11,369	10,518
Current Liabilities:		
Short-term borrowings	273	918
Current portion of long-term debt	16	166
Accounts payable	326	520
Customer deposits and customer prepayments	99	98
Taxes accrued	98	182
Interest accrued	84	83
Dividends declared	76	73
Liabilities held for sale	—	52
Derivative financial instruments	90	233
Other	102	208
Total Current Liabilities	1,164	2,533
Deferred Credits and Other Liabilities:		
Deferred income taxes, net	1,843	1,866
Deferred investment tax credits	26	28
Asset retirement obligations	565	563
Postretirement benefits	318	315
Regulatory liabilities	885	814
Other	198	215
Total Deferred Credits and Other Liabilities	3,835	3,801
Commitments and Contingencies (Note 9)	—	—
Total	$16,368	$16,852

See Notes to Condensed Consolidated Financial Statements.

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SCANA CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

Millions of dollars, except per share amounts	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014
Operating Revenues:				
Electric	$638	$610	$1,266	$1,289
Gas - regulated	130	150	499	608
Gas - nonregulated	199	266	591	719
Total Operating Revenues	967	1,026	2,356	2,616
Operating Expenses:				
Fuel used in electric generation	164	211	338	424
Purchased power	11	16	24	41
Gas purchased for resale	247	318	770	987
Other operation and maintenance	173	174	346	354
Depreciation and amortization	97	95	193	190
Other taxes	59	58	118	116
Total Operating Expenses	751	872	1,789	2,112
Gain on sale of CGT, net of transaction costs	—	—	235	—
Operating Income	216	154	802	504
Other Income (Expense):				
Other income	18	69	37	85
Other expense	(15)	(13)	(27)	(27)
Gain on sale of SCI, net of transaction costs	—	—	107	—
Interest charges, net of allowance for borrowed funds used during construction of $4, $4, $7 and $7	(78)	(76)	(155)	(152)
Allowance for equity funds used during construction	7	8	12	14
Total Other Income (Expense)	(68)	(12)	(26)	(80)
Income Before Income Tax Expense	148	142	776	424
Income Tax Expense	49	46	277	135
Net Income	$99	$96	$499	$289
Basic and Diluted Earnings Per Share of Common Stock	$0.69	$0.68	$3.49	$2.05
Weighted Average Common Shares Outstanding (millions)	142.9	141.7	142.9	141.4
Dividends Declared Per Share of Common Stock	$0.545	$0.525	$1.090	$1.050

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	2015	2014	2015	2014
Net Income	$99	$96	$499	$289
Other Comprehensive Income (Loss), net of tax:				
Unrealized Gains (Losses) on Cash Flow Hedging Activities:				
Unrealized gains (losses) on cash flow hedging activities arising during period, net of tax of $1, $(1), $- and $-	2	(2)	(1)	(1)
Cash flow hedging activities reclassified to interest expense, net tax of $1, $1, $3, and $3	2	2	4	4
Cash flow hedging activities reclassified to gas purchased for resale, net of tax of $1, $-, $6, and $(3)	2	(1)	9	(5)
Net unrealized gains (losses) on cash flow hedging activities	6	(1)	12	(2)
Deferred cost of employee benefit plans, net of tax of $-, $-, $(3) and $-	—	—	(4)	—
Other Comprehensive Income (Loss)	6	(1)	8	(2)
Total Comprehensive Income	$105	$95	$507	$287

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	2015		2014	
Cash Flows From Operating Activities:				
Net income	$499		$289	
Adjustments to reconcile net income to net cash provided from operating activities:				
Gain on sale of subsidiaries	(355	)	—	
Losses from equity method investments	2		2	
Deferred income taxes, net	(91	)	49	
Depreciation and amortization	199		198	
Amortization of nuclear fuel	27		20	
Allowance for equity funds used during construction	(12	)	(14	)
Carrying cost recovery	(6	)	(4	)
Changes in certain assets and liabilities:			—	
Receivables	152		96	
Inventories	2		17	
Prepayments	131		(104	)
Regulatory assets	177		(166	)
Regulatory liabilities	44		(131	)
Accounts payable	(81	)	(4	)
Taxes accrued	(83	)	(110	)
Interest accrued	1		2	
Pension and other post retirement benefits	(1	)	(1	)
Derivative financial instruments	(143	)	83	
Other assets	(42	)	18	
Other liabilities	(43	)	61	
Net Cash Provided From Operating Activities	377		301	
Cash Flows From Investing Activities:				
Property additions and construction expenditures	(594	)	(517	)
Proceeds from sale of subsidiaries	647		—	
Proceeds from investments (including derivative collateral returned)	693		101	
Purchase of investments (including derivative collateral posted)	(607	)	(120	)
Payments upon interest rate derivative contract settlement	(152	)	(34	)
Proceeds upon interest rate derivative contract settlement	10		—	
Net Cash Used For Investing Activities	(3	)	(570	)
Cash Flows From Financing Activities:				
Proceeds from issuance of common stock	14		51	
Proceeds from issuance of long-term debt	491		294	
Repayment of long-term debt	(163	)	(16	)
Dividends	(153	)	(145	)
Short-term borrowings, net	(645	)	21	
Net Cash Provided From (Used for) Financing Activities	(456	)	205	
Net Decrease In Cash and Cash Equivalents	(82	)	(64	)
Cash and Cash Equivalents, January 1	137		136	
Cash and Cash Equivalents, June 30	$55		$72	
Supplemental Cash Flow Information:				

Cash paid for– Interest (net of capitalized interest of $7 and $7)	$ 149	$ 148
– Income taxes	184	193
Noncash Investing and Financing Activities:		
Accrued construction expenditures	89	110
Capital leases	4	2

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, 2015 and 2014
(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, 2014. 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

Subject to future developments in environmental regulations, among other matters, SCE&G expects to retire three units that are or were coal-fired by 2020. The net carrying value of these units is identified as Plant to be Retired, Net in the consolidated financial statements. SCE&G plans to request recovery of and a return on the net carrying value of these units in future rate proceedings in connection with their retirement, and expects that such deferred amounts will be recovered through rates. In the meantime, these units remain in rate base, and SCE&G depreciates them using composite straight-line rates approved by the SCPSC. The net carrying value of three previously retired units is recorded in regulatory assets within unrecovered plant (see Note 2).

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. There were no securities considered to be dilutive potential common stock during any period presented. The Company has issued no securities that would have an antidilutive effect on earnings per share.

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 47% and 48% of PSNC Energy's natural gas inventory at June 30, 2015 and December 31, 2014, respectively, with a carrying value of $13.8 million and $26.1 million, respectively, through either capacity release or agency relationships. Under the terms of the asset management agreements, PSNC Energy receives storage asset management fees of which 75% are credited to rate payers. No fees are received under supply service agreements. The agreements, which expired on March 31, 2015, have been replaced with similar agreements that expire March 31, 2017.

Income Statement Presentation

The Company presents the revenues and expenses of its regulated businesses and its retail natural gas marketing businesses (including those activities of segments described in Note 10) within operating income, and it presents all other activities within other income (expense). Consistent with this presentation, the gain on the sale of CGT is reflected within operating income and the gain on the sale of SCI is reflected within other income (expense).

New Accounting Matters

In April 2014, the FASB issued accounting guidance for reporting discontinued operations and disclosures of disposals of components of an entity. Under this guidance, only those discontinued operations which represent a strategic shift that will

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have a major effect on an entity's operations and financial results should be reported as discontinued operations in the financial statements. As permitted, the Company adopted this guidance for the period ended December 31, 2014.

In May 2014, the FASB issued accounting guidance for revenue arising from contracts with customers that supersedes most current revenue recognition guidance, including industry-specific guidance. The new revenue recognition model provides a five-step analysis in determining when and how revenue is recognized, and will require revenue recognition to depict the transfer of promised goods or services to customers in an amount that reflects the consideration a company expects to receive in exchange for those goods or services. FASB has voted to delay the effective date of the revenue guidance by one year. As a result, the Company is required to adopt this guidance in the first quarter of 2018 and early adoption is permitted beginning in the first quarter of 2017. The Company has not determined the impact this guidance will have on its results of operations, cash flows or financial position.

In April 2015, the FASB issued accounting guidance intended to simplify the presentation of debt issuance costs by requiring that such costs be deducted from the carrying amounts related to debt liabilities when presented in the balance sheet. As permitted, the Company expects to early adopt this guidance in the fourth quarter of 2015. The Company does not expect the adoption of this guidance to have a significant impact on its financial position. The guidance will not affect the Company's results of operations or cash flows.

In April 2015, the FASB issued accounting guidance related to fees paid by a customer in a cloud computing arrangement. Among other things, the guidance clarifies how to account for a software license element included in a cloud computing arrangement, and makes explicit that a cloud computing arrangement not containing a software license element should be accounted for as a service contract. The Company expects to adopt this guidance in the first quarter of 2016. The Company is evaluating this guidance and has not determined what impact it will have on the Company's results of operations, cash flows or financial position.

In July 2015, the FASB issued accounting guidance intended to simplify the subsequent measurement of inventory cost by requiring most inventory to be measured at the lower of cost and net realizable value. The Company expects to adopt this guidance when required in the first quarter of 2017. The Company is evaluating this guidance and has not determined what impact it will have on its results of operations, cash flows or financial position.

2. RATE AND OTHER REGULATORY MATTERS

Rate Matters

Electric - Cost of Fuel

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.

By order dated April 29, 2014, the SCPSC approved a settlement agreement among SCE&G, the ORS, and the SCEUC in which SCE&G agreed to increase its base fuel cost component by approximately $10.3 million for the 12-month period beginning with the first billing cycle of May 2014. The base fuel cost increase was offset by a reduction in SCE&G's rate rider related to pension costs approved by the SCPSC in March 2014. In addition, pursuant to the April 29, 2014 order, the Company's electric revenue for 2014 was reduced by approximately $46 million for adjustments to the fuel cost component and related under-collected fuel balance. Such adjustments are fully offset by the recognition within other income of gains realized from the late 2013 settlement of certain interest rate derivatives which had been entered into in anticipation of the issuance of long-term debt, which gains had been deferred as a regulatory liability. The order also provided for the accrual of certain debt-related carrying costs on its under-collected balance of base fuel costs during the period May 1, 2014 through April 30, 2015. See also Note 6.

The cost of fuel includes amounts paid by SCE&G pursuant to the Nuclear Waste Act for the disposal of spent nuclear fuel. As a result of a November 2013 decision by the Court of Appeals, the DOE set the Nuclear Waste Act fee to zero effective May 16, 2014. The impact of changes to the Nuclear Waste Act fee is considered during annual fuel rate proceedings.

By order dated April 30, 2015, the SCPSC approved a settlement agreement among SCE&G, the ORS, and the SCEUC in which SCE&G agreed to decrease the total fuel cost component of retail electric rates. Under this order, SCE&G is to recover an amount equal to its under-collected balance of base fuel and variable environmental costs as of April 30, 2015, over the subsequent 12-month period beginning with the first billing cycle of May 2015.

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By order dated July 15, 2015, the SCPSC approved a settlement agreement among SCE&G, the ORS, the SCEUC and certain other parties concerning SCE&G's petition for approval to participate in a DER program and to recover DER program costs as a separate component of SCE&G's overall fuel factor. Under this order, SCE&G will, among other things, develop renewable energy facilities with a nameplate capacity of at least 84.5 MW by the end of 2020 and have at least 30 MW of utility-scale solar capacity in service by the end of 2016. The order also requires SCE&G to include bill incentives for solar energy generated by residential and commercial customers. SCE&G will also make bill incentives available for residential customers receiving solar power from community solar-programs.

Electric - Base Rates

In October 2013, SCE&G received an accounting order from the SCPSC directing it to remove from rate base deferred income tax assets arising from capital expenditures related to the New Units and to accrue carrying costs (recorded as a regulatory asset) on those amounts during periods in which they are not included in rate base. Such carrying costs are determined at SCE&G’s weighted average long-term debt borrowing rate. During the three and six months ended June 30, 2015, $2.2 million and $4.1 million, respectively, of such carrying costs were accrued within other income. During the three and six months ended June 30, 2014, $1.4 million and $2.5 million, respectively, of such carrying costs were accrued within other income. SCE&G anticipates that when the New Units are placed in service and accelerated tax deprecation is recognized on them, these deferred income tax assets will decline. When these assets are fully offset by related deferred income tax liabilities, the carrying cost accruals will cease, and the regulatory asset will begin to be amortized.

SCE&G files an IRP with the SCPSC annually which evaluates future electric generation needs based on a variety of factors, including customer energy demands, EPA regulations, reserve margins and fuel costs. SCE&G previously identified six coal-fired units that it has subsequently retired or intends to retire by 2020, subject to future developments in environmental regulations, among other matters. Three of these units were retired by December 31, 2013, and their net carrying value is recorded in regulatory assets as unrecovered plant and is being amortized over the units' previously estimated remaining useful lives as approved by the SCPSC. The net carrying value of the remaining units is included in Plant to be Retired, Net. 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.

In 2013, the SCPSC approved a suite of DSM Programs for development and implementation. Currently, SCE&G offers to its retail electric customers nine distinct programs which are designed to assist customers in reducing their demand for electricity and improving their energy efficiency. SCE&G submits annual filings to the SCPSC related to these programs which include actual program costs, net lost revenues (both forecasted and actual), customer incentives, and net program benefits, among other things. As actual DSM Programs costs are incurred, they are deferred as regulatory assets (see Regulatory Assets and Regulatory Liabilities below) and recovered through a rate rider approved by the SCPSC. The rate rider also provides for recovery of net lost revenues and for a shared savings incentive. The SCPSC approved the following rate riders pursuant to the annual DSM Programs filings, which went into effect as indicated below:

Year	Effective	Amount	
2015	First billing cycle of May	$32.0	million
2014	First billing cycle of May	$15.4	million
2013	First billing cycle of May	$16.9	million

In April 2014, the SCPSC issued an order approving, among other things, SCE&G’s request to utilize approximately $17.8 million of the gains from the late 2013 settlement of certain interest rate derivative instruments, previously deferred as regulatory liabilities, to offset a portion of SCE&G’s DSM Programs rate rider. This order also allowed SCE&G to apply $5.0 million of its storm damage reserve and $5.0 million of the gains from the settlement of certain interest rate derivative instruments to offset previously deferred amounts.

Electric – BLRA

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. Through 2015, requested rate adjustments have been 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 recovery of the following amounts under the BLRA effective for bills rendered on and after October 30 in the following years:

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Year	Action		Amount	
2014	2.8	% Increase	$66.2	million
2013	2.9	% Increase	$67.2	million

On May 29, 2015, SCE&G filed its annual request for approval of revised rates under the provisions of the BLRA. On July 30, 2015, ORS filed a report of its review of SCE&G's request. ORS proposes that SCE&G be allowed to increase its retail rates in the amount of $64.5 million or 2.6%. If approved, the rate change would be effective for bills rendered on and after October 30, 2015.

On March 12, 2015, SCE&G petitioned the SCPSC seeking approval of an updated construction milestone schedule and capital cost schedule for the New Units. The updated construction schedule reflects new substantial completion dates for Units 2 and 3 of June 2019 and June 2020, respectively. The petition also incorporates in the construction cost schedules approximately $698 million (SCE&G’s portion in 2007 dollars) in incremental capital costs that have been identified since the last approved order in November 2012, of which $539 million (SCE&G’s portion in 2007 dollars) are associated with construction delays and other contested costs. The total project capital cost is now estimated at approximately $5.2 billion (SCE&G’s portion in 2007 dollars) or $6.8 billion including escalation and allowance for funds used during construction (SCE&G’s portion in future dollars). As noted in the petition, the construction and capital cost schedules are subject to continuing review and negotiations by the parties. In making this filing, SCE&G does not waive any claims related to delay and other related contested costs with the Consortium.

On June 29, 2015, SCE&G entered into a settlement agreement with the ORS and the SCEUC (one of three non-ORS intervenors) related to the petition to update construction and capital schedules for the New Units. Under this agreement, all settling parties agree to the revised construction and capital cost schedules as outlined in the petition filed with the SCPSC on March 12, 2015. Further, the settling parties agreed to revise the return on common equity for the new nuclear project from 11.0% to 10.5%, for purposes of calculating revised rates under the BLRA, beginning on and after January 1, 2016. The revised rate of return on common equity will remain in effect until the New Units are completed. The settlement agreement is subject to approval by the SCPSC. A public hearing on this matter was held in July 2015, and the SCPSC is expected to issue its order in September 2015. See Note 9.

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 following years:

Year	Action		Amount	
2014	0.6	% Decrease	$2.6	million
2013	No change		-	

On June 15, 2015, SCE&G submitted its annual RSA filing with the SCPSC for the 12-month period ending March 31, 2015. 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 that provides for the recovery of actual gas costs incurred, including transportation costs. 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, and its gas purchasing policies and practices are reviewed annually by the

SCPSC. The annual review conducted for the 12-month period ended July 31, 2014 resulted in the SCPSC issuing an order finding that SCE&G's gas purchasing policies and practices during the review period were reasonable and prudent.

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.

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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 September 2014, in connection with PSNC Energy's 2014 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, 2014.

In May 2014, the NCUC issued an order requiring utilities to adjust rates to reflect changes in the state corporate income tax rate that had been enacted by the North Carolina legislature and to file a proposal to refund amounts previously collected on a provisional basis. Pursuant to the order, PSNC Energy lowered its rates effective July 1, 2014, and refunded the amounts collected on a provisional basis through the normal operation of its Rider D rate mechanism. These amounts were not significant for any period presented.

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. Other than unrecovered plant, 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, 2015	December 31, 2014
Regulatory Assets:		
Accumulated deferred income taxes	$283	$284
Under-collections - electric fuel adjustment clause	—	20
Environmental remediation costs	39	40
AROs and related funding	373	366
Franchise agreements	24	26
Deferred employee benefit plan costs	332	350
Planned major maintenance	—	2
Deferred losses on interest rate derivatives	455	453
Deferred pollution control costs	35	36
Unrecovered plant	131	137
DSM Programs	59	56
Carrying costs on deferred tax assets related to nuclear construction	13	9
Pipeline integrity management costs	13	9
Other	41	35
Total Regulatory Assets	$1,798	$1,823
Regulatory Liabilities:		
Accumulated deferred income taxes	$21	$22
Asset removal costs	720	703
Storm damage reserve	6	6
Deferred gains on interest rate derivatives	123	82
Planned major maintenance	15	—

Other	—	1
Total Regulatory Liabilities	$885	$814

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

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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 which are expected to be recovered in retail electric rates over periods exceeding 12 months.

Environmental remediation costs represent costs associated with the assessment and clean-up of sites currently or formerly owned by the Company, and are expected to be recovered over periods of up to approximately 24 years.

ARO and related funding represents the regulatory asset associated with the legal obligation to decommission and dismantle Summer Station and conditional AROs related to generation, transmission and distribution properties, including gas pipelines. 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 is recovering these amounts through cost of service rates through approximately 2021.

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. Accordingly, in 2013 SCE&G began recovering through utility rates approximately $63 million of deferred pension costs for electric operations over approximately 30 years and approximately $14 million of deferred pension costs for gas operations over approximately 14 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, pursuant to specific SCPSC orders. SCE&G collects and accrues $18.4 million annually for fossil fueled turbine/generation equipment maintenance, and collects and accrues $17.2 million annually for nuclear-related refueling charges.

Deferred losses or gains on interest rate derivatives represent (i) the effective portions of changes in fair value and payments made or received upon settlement of certain interest rate derivatives designated as cash flow hedges and (ii) the changes in fair value and payments made or received upon settlement of certain other interest rate derivatives not so designated. The amounts recorded with respect to (i) are expected to be amortized to interest expense over the lives of the underlying debt through 2043. The amounts recorded with respect to (ii) are expected to be similarly amortized to interest expense over periods up to approximately 50 years except when, in the case of deferred gains, such amounts are applied otherwise at the direction of the SCPSC.

Deferred pollution control costs represent deferred depreciation and operating and maintenance costs associated with the scrubbers installed at certain coal-fired generating plants pursuant to specific regulatory orders. Such costs are being recovered through utility rates through 2045.

Unrecovered plant represents the carrying value of coal-fired generating units, including related materials and supplies inventory, retired from service prior to being fully depreciated. Pursuant to SCPSC approval, SCE&G is amortizing these amounts through cost of service rates over the units' previous estimated remaining useful lives through approximately 2025. Unamortized amounts are included in rate base and are earning a current return.

DSM Programs represent deferred costs associated with such programs. As a result of an April 2015 SCPSC order, deferred costs are currently being recovered over approximately five years through an approved rate rider.

Carrying costs on deferred tax assets related to nuclear construction represent accrued carrying costs on accumulated deferred income tax assets associated with the New Units which are not part of electric base rates. These carrying costs are computed using weighted average long-term debt cost of capital and will be amortized over ten years beginning in approximately 2021.

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Pipeline integrity management costs represent costs incurred to comply with regulatory requirements related to certain natural gas pipelines located near moderate to high density populations. Such costs at SCE&G will be amortized at $1.9 million annually beginning in November 2015. Such costs at PSNC Energy will be considered for recovery through rates in its next general rate proceeding.

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. During the six months ended June 30, 2015, no amounts were applied to offset incremental storm damage costs.

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 specifically 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.

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3.COMMON EQUITY

Changes in common equity during the six months ended June 30, 2015 and 2014 were as follows:

Millions	Common Stock Shares	Common Stock Outstanding Amount	Treasury Shares	Retained Earnings	Accumulated Other Comprehensive Income (Loss) Gains(Losses) on Cash Flow Hedges	Deferred Employee Benefit Plans	Total AOCI	Total Common Equity
Balance as of January 1, 2015	143	$2,388	$(10)	$2,684	$(63)	$(12)	$(75)	$4,987
Net Income				499				499
Other Comprehensive Income (Loss):								
Losses during the period					(1)	(4)	(5)	(5)
Gains/amortization reclassified from AOCI					13	—	13	13
Total Comprehensive Income (Loss)				499	12	(4)	8	507
Issuance of Common Stock	—	14	(1)					13
Dividends Declared				(156)				(156)
Balance as of June 30, 2015	143	$2,402	$(11)	$3,027	$(51)	$(16)	$(67)	$5,351
Balance as of January 1, 2014	141	$2,289	$(9)	$2,444	$(52)	$(8)	$(60)	$4,664
Net Income				289				289
Other Comprehensive Income:								
Gains during the period					(1)	—	(1)	(1)
Losses/amortization reclassified from AOCI					(1)	—	(1)	(1)
Total Comprehensive Income				289	(2)	—	(2)	287
Issuance of Common Stock	1	51						51
Dividends Declared				(148)				(148)
Balance as of June 30, 2014	142	$2,340	$(9)	$2,585	$(54)	$(8)	$(62)	$4,854

Gains and losses on cash flow hedges reclassified during the six months ended June 30, 2015 resulted in higher interest expense of $4 million and higher cost of gas purchased for resale of $9 million. Such reclassifications during the comparable period in 2014 resulted in higher interest expense of $4 million and lower cost of gas purchased for resale of $5 million.

SCANA had 200 million shares of common stock authorized as of June 30, 2015 and December 31, 2014.

4.LONG-TERM DEBT AND LIQUIDITY

Long-term Debt

In May 2014, SCE&G issued $300 million of 4.5% first mortgage bonds due June 1, 2064. Proceeds from this sale were used 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.

On February 2, 2015, SCANA redeemed prior to maturity $150 million of its 7.7% junior subordinated notes at their face value.

In May 2015, SCE&G issued $500 million of 5.1% first mortgage bonds due June 1, 2065. Proceeds from this sale were used 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.

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Substantially all electric utility plant is pledged as collateral in connection with long-term debt.

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:

Millions of dollars	SCANA June 30, 2015	SCANA December 31, 2014	SCE&G June 30, 2015	SCE&G December 31, 2014	PSNC Energy June 30, 2015	PSNC Energy December 31, 2014
Lines of credit:						
Total committed long-term	$300	$300	$1,400	$1,400	$100	$100
Outstanding commercial paper (270 or fewer days)	$15	$179	$258	$709	—	$30
Weighted average interest rate	0.69 %	0.54 %	0.46 %	0.52 %	—	0.65 %
Letters of credit supported by LOC	$3	$3	$0.3	$0.3	—	—
Available	$282	$118	$1,142	$691	$100	$70

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 2019. In addition, SCE&G is a party to a three-year credit agreement in the amount of $200 million, which expires in October 2016. 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 TD Bank N.A. These letters of credit expire, subject to renewal, in the fourth quarter of 2019.

5. INCOME TAXES

During 2013 and 2014, the Company amended certain of its tax returns to claim certain tax-defined research and development deductions and credits. In connection with these filings, the Company recorded an unrecognized tax benefit of $16 million. If recognized, $13 million of the tax benefit would affect the Company's effective tax rate. It is reasonably possible that this tax benefit will increase by an additional $2 million within the next 12 months. It is also reasonably possible that this tax benefit may decrease by $7 million within the next 12 months. No other material changes in the status of the Company's tax positions have occurred through June 30, 2015.

The Company recognizes interest accrued related to unrecognized tax benefits within interest expense and recognizes tax penalties within other expenses. Because no refunds related to the unrecognized tax benefits have yet been received, the Company has not recorded any interest expense or penalties associated with them.

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

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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 their 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 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.

Unrealized gains and losses on qualifying cash flow hedges of nonregulated operations are deferred in AOCI. When the hedged transactions affect earnings, 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. In cases in which 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 locks or forward starting swap agreements that are designated as cash flow hedges. Except as described in the following paragraph, 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. For the holding company or nonregulated subsidiaries, such amounts are recorded in AOCI. Such amounts are amortized to interest expense over the term of the underlying debt. Ineffective portions of fair value changes are recognized in income.

Pursuant to regulatory orders, interest rate derivatives entered into by SCE&G after October 2013 are not designated as cash flow hedges, and all related fair value changes and settlement amounts are recorded as regulatory assets or liabilities. Interest rate derivatives entered into before October 2013 were designated as cash flow hedges, and for such instruments only the effective portion of fair value changes and settlement amounts are recorded in regulatory assets or regulatory liabilities. Upon settlement, losses on swaps are amortized over the lives of related debt issuances, and gains are applied to under-collected fuel, are amortized to interest expense or are applied as otherwise directed by the SCPSC.

Cash payments made or received upon termination of these financial instruments are classified as investing activities for cash flow statement purposes.

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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, 2015				
Commodity contracts	10,170,000	8,290,000	3,702,627	22,162,627
Energy management contracts (a)	—	—	35,650,235	35,650,235
Total (a)	10,170,000	8,290,000	39,352,862	57,812,862
As of December 31, 2014				
Commodity contracts	6,840,000	7,951,000	3,446,720	18,237,720
Energy management contracts (b)	—	—	37,495,339	37,495,339
Total (b)	6,840,000	7,951,000	40,942,059	55,733,059

(a) Includes an aggregate 2,201,175 MMBTU related to basis swap contracts in Energy Marketing.
(b) Includes an aggregate 933,893 MMBTU related to basis swap contracts in Energy Marketing.

The Company was party to interest rate swaps designated as cash flow hedges with aggregate notional amounts of $120.0 million at June 30, 2015 and $124.4 million at December 31, 2014. The Company was party to interest rate swaps not designated as cash flow hedges with an aggregate notional amount of $835.0 million at June 30, 2015 and $1.1 billion at December 31, 2014.

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, 2015				
Designated as hedging instruments				
Interest rate contracts			Derivative financial instruments	$5
			Other deferred credits and other liabilities	24
Commodity contracts	Derivative financial instruments	$1	Derivative financial instruments	3
Total		$1		$32
Not designated as hedging instruments				
Interest rate contracts	Other deferred debits and other assets	$41	Derivative financial instruments	$74
			Other deferred credits and other liabilities	12
Commodity contracts	Other current assets	2		
Energy management contracts	Other current assets	9	Other current assets	1 8

			Derivative financial instruments	
	Other deferred debits and other assets	4	Other deferred credits and other liabilities	4
Total		$56		$99

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As of December 31, 2014				
Designated as hedging instruments				
Interest rate contracts			Derivative financial instruments	$5
			Other deferred credits and other liabilities	28
Commodity contracts			Other current assets	1
			Derivative financial instruments	11
Total				$45
Not designated as hedging instruments				
Interest rate contracts			Derivative financial instruments	$207
			Other deferred credits and other liabilities	17
Commodity contracts	Other current assets	$1		
Energy management contracts	Other current assets	15	Other current assets	5
			Derivative financial instruments	10
	Other deferred debits and other assets	5	Other deferred credits and other liabilities	5
Total		$21		$244

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

Derivatives Designated as Fair Value Hedges

The Company had no interest rate or commodity derivatives designated as fair value hedges for any period presented.

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	2015	2014	Location	2015	2014
Three Months Ended June 30,					
Interest rate contracts	$2	$(1)	Interest expense	$(1)	—
Six Months Ended June 30,					
Interest rate contracts	—	$(4)	Interest expense	$(1)	$(1)

	Gain (Loss) Recognized in OCI, net of tax (Effective Portion)			Gain (Loss) Reclassified from AOCI into Income, net of tax (Effective Portion)	
Millions of dollars	2015	2014	Location	2015	2014
Three Months Ended June 30,					
Interest rate contracts	$2	$(2)	Interest expense	$(2)	$(2)
Commodity contracts	—	—	Gas purchased for resale	(2)	1

Total	$2	$(2)		$(4)	$(1)
Six Months Ended June 30,					
Interest rate contracts	—	$(4)	Interest expense	$(4)	$(4)
Commodity contracts	$(1)	3	Gas purchased for resale	(9)	5
Total	$(1)	$(1)		$(13)	$1

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As of June 30, 2015, 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 $7.2 million as an increase to interest expense, assuming natural gas and financial markets remain at their current levels. As of June 30, 2015, all of the Company's commodity cash flow hedges settle by their terms before the end of the second quarter of 2018.

As of June 30, 2015, the Company expects that during the next 12 months reclassifications from regulatory accounts to earnings arising from cash flow hedges designated as hedging instruments will include approximately $2.3 million as an increase to interest expense, assuming financial markets remain at their current levels.

Hedge Ineffectiveness

Other losses recognized in income representing ineffectiveness on interest rate hedges designated as cash flow hedges were insignificant in the three months and six months ended June 30, 2015 and 2014, respectively.

Derivatives not designated as Hedging Instruments

	Gain (Loss) Deferred in Regulatory Accounts			Gain Reclassified from Deferred Accounts into Income	
Millions of dollars	2015	2014	Location	2015	2014
Three Months Ended June 30,					
Interest rate contracts	$132	$(73)	Other income	$1	$55
Six Months Ended June 30,					
Interest rate contracts	$37	$(185)	Other income	$5	$55

As of June 30, 2015, the Company expects that during the next 12 months reclassifications from regulatory accounts to earnings arising from derivatives not designated as hedges will include $0.5 million as an increase to interest expense.

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. 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, 2015 and December 31, 2014, the Company has posted $62.6 million and $152.4 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 Other Current Assets on the condensed consolidated balance sheets. Collateral related to noncurrent positions is recorded in Other within Deferred Debits and Other Assets on the condensed consolidated balance sheets. If all of the contingent features underlying these instruments had been fully triggered as of June 30, 2015 and December 31, 2014, the Company could have been required to post an additional $48.7 million and $129.8 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, 2015 and December 31, 2014 is $111.3 million and $282.2 million, respectively.

In addition, as of June 30, 2015 and December 31, 2014, 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 had been fully triggered as of June 30, 2015 and December 31, 2014, the Company could request $23.0 million and

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$- 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, 2015 and December 31, 2014 is $23.0 million and $- million, respectively. In addition, as of June 30, 2015, the Company could have called on letters of credit in the amount of $3.0 million related to $13.0 million in commodity derivatives that are in a net asset position, compared to letters of credit of $9.2 million related to derivatives of $20.0 million at December 31, 2014, if all the contingent features underlying these instruments had been fully triggered.

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

				Gross Amounts Not Offset in the Statement of Financial Position		
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	Financial Instruments	Cash Collateral Received	Net Amount
As of June 30, 2015						
Interest rate contracts	$41	—	$41	$(18)	—	$23
Commodity contracts	3	$(1)	2	—	—	2
Energy management contracts	13	—	13	—	—	13
Total	$57	$(1)	$56	$(18)	—	$38
Balance sheet location	Other current assets		$11			
	Other deferred debits and other assets		45			
	Total		$56			
As of December 31, 2014						
Commodity contracts	$1	—	$1	—	—	$1
Energy management contracts	20	—	20	—	—	20
Total	$21	—	$21	—	—	$21
Balance sheet location	Other current assets		$16			
	Other deferred debits and other assets		5			
	Total		$21			

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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		Net Amount
				Financial Instruments	Cash Collateral Posted	
As of June 30, 2015						
Interest rate contracts	$115	—	$115	$(18)	$(52)	$45
Commodity contracts	3	—	3	—	(3)	—
Energy management contracts	13	—	13	—	(8)	5
Total	$131	—	$131	$(18)	$(63)	$50
Balance sheet location	Other current assets		$1			
	Derivative financial instruments		90			
	Other deferred credits and other liabilities		40			
	Total		$131			
As of December 31, 2014						
Interest rate contracts	$257	—	$257	—	$(131)	$126
Commodity contracts	12	—	12	—	(10)	2
Energy management contracts	20	—	20	—	(11)	9
Total	$289	—	$289	—	$(152)	$137
Balance sheet location	Other current assets		$6			
	Derivative financial instruments		233			
	Other deferred credits and other liabilities		50			
	Total		$289			

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 data. Fair value measurements, and the level within the fair value hierarchy in which the measurements fall, were as follows:

	As of June 30, 2015		As of December 31, 2014	
Millions of dollars	Level 1	Level 2	Level 1	Level 2
Assets:				
Available for sale securities	$14	—	$13	—
Interest rate contracts	—	$41	—	—
Commodity contracts	3	—	1	—
Energy management contracts	—	13	—	$20
Liabilities:				
Interest rate contracts	—	115	—	257

Commodity contracts	—	3	1	11
Energy management contracts	1	15	5	18

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There were no Level 3 fair value measurements for either period presented, and 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 were as follows:

	June 30, 2015		December 31, 2014	
Millions of dollars	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Long-term debt	$6,034.2	$6,525.2	$5,697.2	$6,592.1

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

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

	Pension Benefits		Other Postretirement Benefits	
Millions of dollars	2015	2014	2015	2014
Three months ended June 30,				
Service cost	$5.8	$5.0	$1.4	$1.3
Interest cost	9.5	10.2	2.9	3.1
Expected return on assets	(15.5)	(16.8)	—	—
Prior service cost amortization	1.0	1.0	0.1	0.1
Amortization of actuarial losses	3.5	1.3	0.6	0.1
Net periodic benefit cost	$4.3	$0.7	$5.0	$4.6
Six months ended June 30,				
Service cost	$11.5	$10.0	$2.8	$2.5
Interest cost	19.1	20.4	5.8	6.2
Expected return on assets	(31.0)	(33.6)	—	—
Prior service cost amortization	2.0	2.0	0.2	0.2
Amortization of actuarial losses	7.0	2.6	1.1	0.2
Net periodic benefit cost	$8.6	$1.4	$9.9	$9.1

No significant contribution to the pension trust is expected for the foreseeable future, nor is a limitation on benefit payments expected to apply. SCE&G recovers current pension costs through either a rate rider that may be adjusted annually for retail electric operations or through cost of service rates for gas operations.

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 SCE&G's nuclear power plant. Price-Anderson provides funds up to $12.9 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 $127.3 million per reactor owned for each nuclear incident occurring at any reactor in the United States, provided that not more than $18.9 million of the liability per reactor would be assessed per year. SCE&G’s maximum

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assessment, based on its two-thirds ownership of Summer Station Unit 1, would be $84.8 million per incident, but not more than $12.6 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 resulting from an event of nuclear origin. 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 $45.9 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, 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.

New Nuclear Construction

In 2008, SCE&G, on behalf of itself and as agent for Santee Cooper, contracted with the Consortium for the design and construction of the New Units at the site of Summer Station.

SCE&G's current ownership share in the New Units is 55%. As discussed below, under an agreement signed in January 2014 (and subject to customary closing conditions, including necessary regulatory approvals), SCE&G has agreed to acquire an additional 5% ownership in the New Units from Santee Cooper.

EPC Contract and BLRA Matters

The construction of the New Units and SCE&G's related recovery of financing costs through rates is subject to review and approval by the SCPSC as provided for in the BLRA. Under the BLRA, the SCPSC has approved, among other things, a milestone schedule and a capital costs estimates schedule for the New Units. This approval constitutes a final and binding determination that the New Units are used and useful for utility purposes, and that the capital costs associated with the New Units are prudent utility costs and expenses and are properly included in rates, so long as the New Units are constructed or are being constructed within the parameters of the approved milestone schedule, including specified schedule contingencies, and the approved capital costs estimates schedule. Subject to the same conditions, the BLRA provides that SCE&G may apply to the SCPSC annually for an order to recover through revised rates SCE&G's weighted average cost of capital applied to all or part of the outstanding balance of construction work in progress concerning the New Units. Such annual rate changes are described in Note 2. As of June 30, 2015, SCE&G's investment in the New Units totaled $3.0 billion, for which the financing costs on $2.4 billion have been reflected in rates under the BLRA.

The SCPSC granted initial approval of the construction schedule, including 146 milestones within that schedule, and related forecasted capital costs in 2009. The NRC issued COLs in March 2012. In November 2012, the SCPSC approved an updated milestone schedule and additional updated capital costs for the New Units. In addition, the SCPSC approved revised substantial completion dates for the New Units based on that March 2012 issuance of the

COL and the amounts agreed upon by SCE&G and the Consortium in July 2012 to resolve known claims by the Consortium for costs related to COL delays, design modifications of the shield building and certain prefabricated structural modules for the New Units and unanticipated rock conditions at the site. In October 2014, the South Carolina Supreme Court affirmed the SCPSC's order on appeal.

The substantial completion dates currently approved by the SCPSC for Units 2 and 3 are March 15, 2017 and May 15, 2018. The SCPSC also approved an 18-month contingency period beyond each of these dates, and for each of the 146 milestones in the schedule. A petition requesting revisions to these dates is discussed below.

Since the settlement of delay-related claims in 2012, the Consortium has continued to experience delays in the schedule, including those related to fabrication and delivery of sub-modules for the New Units. The fabrication and delivery of sub-modules have been and remain focus areas of the Consortium. Shield building panels are considered critical path items for both New Units, and the current schedule for production of such panels will require mitigation to support the updated substantial completion dates (see below). The sub-modules for CA01, which houses components inside the containment vessel, were delivered, and its on-site fabrication was completed such that CA01 was placed on the nuclear island of Unit 2 on July 23, 2015.

During the fourth quarter of 2013, the Consortium began a full re-baselining of the Unit 2 and Unit 3 construction schedules to incorporate a more detailed evaluation of the engineering and procurement activities necessary to accomplish the schedules and to provide a detailed reassessment of the impact of the revised Unit 2 and Unit 3 schedules on engineering and design resource allocations, procurement, construction work crew efficiencies, and other items. The result was a revised, fully integrated project schedule with timing of specific construction activities (Revised, Fully-Integrated Construction Schedule) along with related cost information.

The Revised, Fully-Integrated Construction Schedule indicated that the substantial completion of Unit 2 was expected to occur in mid-June 2019 and that the substantial completion of Unit 3 was expected to be approximately 12 months later. SCE&G has not, however, accepted the Consortium's contention that the new substantial completion dates are made necessary by delays that are excusable under the EPC Contract. The Consortium continues to refine and update the Revised, Fully-Integrated Construction Schedule as designs are finalized, as construction progresses, and as additional information is received.

As discussed above, the milestone schedule approved by the SCPSC in November 2012 provides for 146 milestone dates, each of which is subject to an 18-month schedule contingency. As of June 30, 2015, 106 milestones have been completed, and three of the remaining milestones have not been completed within their 18-month contingency periods. In light of the Revised, Fully-Integrated Schedule, it is anticipated that the completion dates for a substantial number of the remaining milestone dates will also extend beyond their contingency periods. Further, capital costs (in 2007 dollars) and gross construction cost estimates (including escalation and AFC) are projected to exceed amounts currently approved by the SCPSC of $4.5 billion and $5.8 billion, respectively.

As such, in March 2015 SCE&G petitioned the SCPSC for an order to update the BLRA milestone schedule based on revised substantial completion dates for Units 2 and 3 of June 2019 and June 2020, respectively, each subject to an 18-month contingency period. In addition, that petition included certain updated owner's costs ($245 million) and other capital costs ($453 million) which, if approved, would reset projected capital costs (in 2007 dollars) and gross construction cost estimates (including escalation and AFC) to $5.2 billion and $6.8 billion, respectively. These projections include cost amounts related to the Revised, Fully-Integrated Construction Schedule for which SCE&G has not accepted responsibility and which may be the subject of dispute. As such, the petition does not reflect the resolution of negotiations.

In June 2015, SCE&G entered into a settlement agreement with ORS and the SCEUC (one of three non-ORS intervenors) in which the settling parties agreed to support approval of the revised construction and capital cost schedules and agreed to revise the allowed return on equity for new nuclear construction from 11.00% to 10.50% applied prospectively for the purpose of calculating revised rates sought by SCE&G under the BLRA on and after January 1, 2016, until such time as the New Units are completed. This settlement agreement among SCE&G, ORS and the SCEUC is subject to approval by the SCPSC.

The SCPSC held a public hearing related to the petition and the settlement agreement in July 2015. While the BLRA provides that the SCPSC shall grant the petition for modification if the record justifies a finding that the change is not the result of imprudence by SCE&G, SCE&G cannot predict the outcome of this regulatory process. As discussed in Note 2, SCE&G expects the SCPSC to issue its order on the petition and the settlement agreement in September 2015.

Additional claims by the Consortium or SCE&G involving the project schedule and budget may arise as the project continues. The parties to the EPC Contract have established both informal and formal dispute resolution procedures in order to resolve such issues. SCE&G expects to resolve all disputes (including any ultimate disagreements involving the preliminary cost estimates provided by the Consortium in the third quarter of 2014) through both the informal and formal procedures and anticipates that any costs that arise through such dispute resolution processes, as well as other costs identified from time to time, will be recoverable through rates.

Santee Cooper Matters

As noted above, SCE&G has agreed to acquire an additional 5% ownership in the New Units from Santee Cooper. Under the terms of this agreement, SCE&G will acquire a 1% ownership interest in the New Units at the commercial operation date of Unit 2, an additional 2% ownership interest no later than the first anniversary of such commercial operation date, and the final 2% no later than the second anniversary of such commercial operation date. SCE&G has agreed to pay an amount equal to Santee Cooper's actual cost of the percentage conveyed as of the date of each conveyance. In addition, the agreement provides that Santee Cooper will not transfer any of its remaining interest in the New Units to third parties until the New Units are complete. This transaction will not affect the payment obligations between the parties during construction for the New Units, nor is it anticipated that the payments for the additional ownership interest would be reflected in a revised rates filing under the BLRA. Based on the current milestone schedule and capital costs schedule approved by the SCPSC in November 2012, SCE&G’s estimated cost would be approximately $500 million for the additional 5% interest being acquired from Santee Cooper. This cost figure is expected to be higher in light of the delays and related costs and regulatory petition discussed above.

Nuclear Production Tax Credits

The IRS has notified SCE&G that, subject to a national megawatt capacity limitation, the electricity to be produced by each of the New Units (advanced nuclear units, as defined) would qualify for nuclear production tax credits under Section 45J of the Internal Revenue Code to the extent that such New Unit is operational before January 1, 2021 and other eligibility requirements are met. These nuclear production tax credits (related to SCE&G's 55% share of both New Units) could total as much as approximately $1.4 billion. Such credits would be earned over the first eight years of each New Unit's operations and would be realized by SCE&G over those years or during allowable carry-forward periods. Based on the above substantial completion dates provided by the Consortium of June 2019 and June 2020 for Units 2 and 3, respectively, both New Units are expected to be operational and to qualify for the nuclear production tax credits; however, further delays in the schedule or changes in tax law could impact such conclusions. To the extent that production tax credits are realized, their benefits are expected to be provided directly to SCE&G's electric customers as so realized.

Other Project Matters

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. SCE&G prepared and submitted an integrated response plan for the New Units to the NRC in August 2013. That plan is currently under review by the NRC and SCE&G does not anticipate any additional regulatory actions as a result of that review, but it cannot predict future regulatory activities or how such initiatives would impact construction or operation of the New Units.

Environmental

The Company's operations are subject to extensive regulation by various federal and state authorities in the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes. Applicable statutes and rules include the CAA, CWA, Nuclear Waste Act and CERCLA, among others. In many cases, regulations proposed by such authorities could have a significant impact on the Company's financial condition, results of operations and cash flows. In addition, the Company often cannot predict what conditions or requirements will be imposed by regulatory or legislative proposals. To the extent that compliance with environmental regulations or legislation results in capital expenditures or operating costs, the Company expects to recover such expenditures and costs through existing ratemaking provisions.

From a regulatory perspective, SCANA, SCE&G and GENCO continually monitor and evaluate their current and projected emission levels and strive to comply with all state and federal regulations regarding those emissions. SCE&G and GENCO participate in the sulfur dioxide and nitrogen oxide emission allowance programs with respect to coal plant emissions and also have constructed additional pollution control equipment at several larger coal-fired electric generating plants. Further, SCE&G is engaged in construction activities of the New Units which are expected to reduce GHG emission levels significantly once they are completed and dispatched by potentially displacing some of the current coal-fired generation sources. These actions are expected to address many of the rules and regulations discussed herein.

The EPA issued a revised carbon standard for new power plants by re-proposing NSPS under the CAA for emissions of carbon dioxide (CO_2) from newly constructed fossil fuel-fired units. The final rule was issued on August 3, 2015 and requires all new coal-fired power plants to meet a carbon emission rate of 1,400 pounds CO_2 per MWh and new natural gas units to meet 1,000 pounds CO_2 per MWh. While most new natural gas plants will not be required to include any new technologies, no new coal-fired plants could be constructed without partial carbon capture and sequestration capabilities. The Company is evaluating the final rule, but does not plan to construct new coal-fired units in the foreseeable future. In addition, on August 3, 2015, the EPA issued its final rule on emission guidelines for states to follow in developing plans to address GHG emissions from existing units. The rule includes state-specific goals for reducing national carbon dioxide emissions by 32% from 2005 levels by 2030. The rule also provides for nuclear reactors under construction, such as the New Units, to count towards compliance and establishes a phased-in compliance approach beginning in 2022. The Company is currently evaluating the rule and expects any costs incurred to comply with such rule to be recoverable through rates.

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In July 2011, the EPA issued the CSAPR to reduce emissions of sulfur dioxide and nitrogen oxide from power plants in the eastern half of the United States. A series of court actions stayed this rule until October 23, 2014, when the Court of Appeals granted a motion to lift the stay. On December 3, 2014, the EPA published an interim final rule that aligns the dates in the CSAPR text with the revised court-ordered schedule, thus delaying the implementation dates to 2015 for Phase 1 and to 2017 for Phase 2. The CSAPR replaces the CAIR and requires a total of 28 states to reduce annual sulfur dioxide emissions and annual or ozone season nitrogen oxide emissions to assist in attaining the ozone and fine particle NAAQS. The rule establishes an emissions cap for sulfur dioxide and nitrogen oxide and limits the trading for emission allowances by separating affected states into two groups with no trading between the groups. On July 28, 2015, the Court of Appeals held that Phase 2 emissions budgets for certain states, including South Carolina, required reductions in emissions beyond the point necessary to achieve downwind attainment and were, therefore, invalid. The Court of Appeals remanded CSAPR, without vacating the rule, to the EPA for further consideration. The opinion of the Court of Appeals has no immediate impact on SCE&G and GENCO or their generation operations. Air quality control installations that SCE&G and GENCO have already completed have positioned them to comply with the existing allowances set by the CSAPR. Any cost incurred to comply with CSAPR are expected to be recoverable through rates.

In April 2012, the EPA's MATS rule containing new standards for mercury and other specified air pollutants became effective. The rule provides up to four years for generating facilities to meet the standards, and the Company's evaluation of the rule is ongoing. The Company's decision to retire certain coal-fired units or convert them to burn natural gas (see Note 1) and its project to build the New Units along with other actions are expected to result in the Company's compliance with MATS. On November 19, 2014, the EPA finalized its reconsideration of certain provisions applicable during startup and shutdown of generating facilities. SCE&G and GENCO have received a one year extension (until April 2016) to comply with MATS at Cope, McMeekin, Wateree and Williams Stations. These extensions will allow time to convert McMeekin Station to burn natural gas and to install additional pollution control devices at the other plants that will enhance the control of certain MATS-regulated pollutants. On June 29, 2015, the U.S. Supreme Court ruled that the EPA unreasonably failed to consider costs in its decision to regulate, and remanded a case challenging the regulation on that basis to the Court of Appeals. The ruling, however, is not expected to have an impact on SCE&G or GENCO due to the aforementioned retirements and conversions.

The CWA provides for the imposition of effluent limitations that require treatment for wastewater discharges. Under the CWA, compliance with applicable limitations is achieved under state-issued NPDES permits. As a facility’s NPDES permit is renewed (every five years), any new effluent limitations would be incorporated. The ELG Rule was published in the Federal Register on June 7, 2013, and is expected to be finalized no later than September 30, 2015. Once the rule becomes effective, state regulators will modify facility NPDES permits to match more restrictive standards, thus requiring facilities to retrofit with new wastewater treatment technologies. Compliance dates will vary by type of wastewater, and some will be based on a facility's five year permit cycle and thus may range from 2018 to 2023. Based on the proposed rule, the Company expects that wastewater treatment technology retrofits will be required at Williams and Wateree Stations and may be required at other facilities.

The CWA Section 316(b) Existing Facilities Rule became effective in October 2014. This rule establishes national requirements for the location, design, construction and capacity of cooling water intake structures at existing facilities that reflect the best technology available for minimizing the adverse environmental impacts of impingement and entrainment. SCE&G and GENCO are conducting studies and implementing plans to ensure compliance with this rule. In addition, Congress is expected to consider further amendments to the CWA. Such legislation may include toxicity-based standards as well as limitations to mixing zones.

On April 17, 2015, the EPA's final rule for CCR was published in the Federal Register and will become effective in the fourth quarter of 2015. This rule regulates CCR as a non-hazardous waste under Subtitle D of the Resource

Conservation and Recovery Act and imposes certain requirements on ash storage ponds at SCE&G's and GENCO's coal-fired generating facilities. Although the full effects of this rule are still being evaluated, SCE&G and GENCO have already closed or have begun the process of closure of all of their ash storage ponds and have previously recognized AROs for such ash storage ponds under existing requirements. The Company does not expect the incremental compliance costs associated with this rule to be significant and expects to recover such costs in future rates.

The Nuclear Waste Act required that the United States government accept and permanently dispose of high-level radioactive waste and spent nuclear fuel by January 31, 1998, and it imposed on utilities the primary responsibility for storage of their spent nuclear fuel until the repository is available. SCE&G entered into a Standard Contract for Disposal of Spent Nuclear Fuel and/or High-Level Radioactive Waste with the DOE in 1983. As of June 30, 2015, the federal government has not accepted any spent fuel from Summer Station Unit 1, and it remains unclear when the repository may become available. SCE&G has on-site spent nuclear fuel storage capability in its existing fuel pool until at least 2017 and is constructing a dry

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cask storage facility to accommodate the spent nuclear fuel output for the life of Summer Station Unit 1. SCE&G may evaluate other technology as it becomes available.

The provisions of CERCLA authorize the EPA to require the clean-up of hazardous waste sites. The states of South Carolina and North Carolina have similar laws. The Company maintains an environmental assessment program to identify and evaluate current and former operations sites that could require clean-up. In addition, regulators from the EPA and other federal or state agencies periodically notify the Company that it may be required to perform or participate in the investigation and remediation of a hazardous waste site. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. These estimates are refined as additional information becomes available; therefore, actual expenditures may differ significantly from the original estimates. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Such amounts are recorded in regulatory assets and amortized, with recovery provided through rates.

SCE&G is responsible for four decommissioned MGP sites in South Carolina which contain residues of by-product 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 at least through 2017 and will cost an additional $19.1 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, 2015, deferred amounts, net of amounts previously recovered through rates and insurance settlements, totaled $35.0 million and are included in regulatory assets.

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 the parent company, a services company and other nonreportable segments that were insignificant for all periods presented. In addition, All Other includes gains from the sales of CGT and SCI (see Note 11) and their operating results and assets prior to their sale in the first quarter of 2015. CGT and SCI were nonreportable segments during all periods presented. For the period ended June 30, 2015, operating income and net income for All Other include $235 million and $202 million, respectively, related to the sales of CGT and SCI. External revenue and intersegment revenue for All Other related to CGT and SCI were not significant during any period presented.

Millions of dollars	External Revenue	Intersegment Revenue	Operating Income	Net Income
Three Months Ended June 30, 2015				
Electric Operations	$638	$1	$216	n/a
Gas Distribution	129	—	5	n/a
Retail Gas Marketing	71	—	n/a	$(6)
Energy Marketing	128	32	n/a	3
All Other	1	93	—	(10)
Adjustments/Eliminations	—	(126)	(5)	112
Consolidated Total	$967	$—	$216	$99
Six Months Ended June 30, 2015				
Electric Operations	$1,266	$3	$415	n/a
Gas Distribution	497	—	101	n/a
Retail Gas Marketing	276	—	n/a	$21

Energy Marketing	315	67	n/a	9
All Other	5	207	237	197
Adjustments/Eliminations	(3)	(277)	49	272
Consolidated Total	$2,356	$—	$802	$499

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Three Months Ended June 30, 2014				
Electric Operations	$610	$2	$143	n/a
Gas Distribution	146	—	7	n/a
Retail Gas Marketing	79	—	n/a	$(3)
Energy Marketing	187	54	n/a	—
All Other	9	104	6	(2)
Adjustments/Eliminations	(5)	(160)	(2)	101
Consolidated Total	$1,026	$—	$154	$96
Six Months Ended June 30, 2014				
Electric Operations	$1,289	$4	$341	n/a
Gas Distribution	601	—	104	n/a
Retail Gas Marketing	299	—	n/a	$19
Energy Marketing	420	107	n/a	7
All Other	18	214	14	2
Adjustments/Eliminations	(11)	(325)	45	261
Consolidated Total	$2,616	$—	$504	$289

Segment Assets	June 30, 2015	December 31, 2014
Electric Operations	$10,454	$10,182
Gas Distribution	2,481	2,487
Retail Gas Marketing	114	140
Energy Marketing	106	150
All Other	989	1,474
Adjustments/Eliminations	2,224	2,419
Consolidated Total	$16,368	$16,852

11. DISPOSITIONS

In December 2014, SCANA entered into definitive agreements to sell CGT and SCI. CGT is an interstate natural gas pipeline regulated by FERC that transports natural gas in South Carolina and southeastern Georgia, and it was sold to Dominion Resources, Inc. SCI provides fiber optic communications and other services and builds, manages and leases communications towers in several southeastern states, and it was sold to a subsidiary of Spirit Communications. These sales closed in the first quarter of 2015 and resulted in a pre-tax gain recognized of approximately $342 million. As further described in Note 1, the pre-tax gain from the sale of CGT is included within Operating Income and the pre-tax gain from the sale of SCI is included within Other Income (Expense) on the condensed consolidated income statement.

CGT and SCI operate principally in wholesale markets, whereas the Company's primary focus is the delivery of energy-related products and services to retail markets. In addition, neither CGT nor SCI met accounting criteria for disclosure as a reportable segment and were included within All Other in Note 10. The sales of CGT and SCI did not represent a strategic shift that will have a major effect on SCANA's operations; therefore, these sales do not meet the criteria for classification as discontinued operations.

The carrying values of the major classes of assets and liabilities classified as held for sale in the consolidated balance sheet as of December 31, 2014, were as follows:

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Millions of dollars	CGT	SCI	Total
Assets Held for Sale			
Utility Plant, Net	$288.4	—	$288.4
Nonutility Property and Investments, Net	0.6	$40.1	40.7
Current Assets	6.5	3.9	10.4
Deferred Debits and Other Assets	0.9	0.2	1.1
Total Assets Held for Sale	$296.4	$44.2	$340.6
Liabilities Held for Sale			
Current Liabilities	$3.5	$2.2	$5.7
Deferred Credits and Other Liabilities	42.9	3.1	46.0
Total Liabilities Held for Sale	$46.4	$5.3	$51.7

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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, 2014.

RESULTS OF OPERATIONS
FOR THE THREE AND SIX MONTHS ENDED JUNE 30, 2015
AS COMPARED TO THE CORRESPONDING PERIODS IN 2014

Earnings Per Share

The Company reports earnings as determined in accordance with GAAP. Management believes that, in addition to reported earnings under GAAP, the Company's GAAP-adjusted weather-normalized net earnings provides a meaningful representation of its fundamental earnings power and can aid in performing period-over-period financial analysis and comparison with peer group data. In management's opinion, in addition to operating income for regulated businesses, GAAP-adjusted weather-normalized net earnings is a useful indicator of the financial results of the Company's primary businesses. This measure is also a basis for management's provision of earnings guidance and growth projections, and it is used by management in making resource allocation and other budgetary and operational decisions including determining eligibility for certain incentive compensation payments. This non-GAAP performance measure is not intended to replace the GAAP measure of net earnings, but is offered as a supplement to it. A reconciliation of reported (GAAP) earnings per share to GAAP-adjusted weather-normalized net earnings per share is provided in the table below:

	Second Quarter		Year to Date	
	2015	2014	2015	2014
Reported (GAAP) earnings per share	$0.69	$0.68	$3.49	$2.05
Deduct:				
Gain on sale of CGT	—	—	0.95	—
Gain on sale of SCI	—	—	0.46	—
SCE&G Electric - effect of abnormal weather	0.06	0.06	0.11	0.16
GAAP-adjusted weather-normalized net earnings per share	$0.63	$0.62	$1.97	$1.89

Second Quarter and Year to Date

Year to date earnings per share on a GAAP basis increased due to the sale of CGT and SCI in the first quarter of 2015. Second quarter and year to date earnings per share increased due to higher electric operations margins, higher gas distribution margins and lower operation and maintenance expenses. These increases were partially offset by higher depreciation, higher property taxes, higher interest cost, higher income taxes and dilution from additional shares outstanding, as further discussed below.

Discussion of above adjustments:

The sales of CGT and SCI were closed in the first quarter of 2015. These subsidiaries operated principally in wholesale markets, whereas the Company's primary focus is the delivery of energy-related products and services to retail markets. Therefore, CGT and SCI were not a part of the Company's core business. See Note 11 to the condensed consolidated financial statements.

SCE&G estimates the effects of abnormal weather on its electric business by comparing actual temperatures in its service territory to a 15-year rolling average of temperatures. The result is used in developing an estimate of electric margin revenue, using average margin rates, attributable to the effects of abnormal weather.

Management believes the above adjustments are appropriate in determining the non-GAAP financial performance measure. Such non-GAAP measure reflects management's decision that wholesale gas transportation and telecommunications

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operations were not a part of the Company's core businesses and would not align with the Company's commitment to serve retail customers on a long-term basis. The non-GAAP measure also provides a consistent basis upon which to measure performance by excluding the effects on per share earnings of abnormal weather in the electric business.

Dividends Declared

SCANA’s Board of Directors has declared the following dividends on common stock during 2015:

Declaration Date	Dividend Per Share	Record Date	Payment Date
February 20, 2015	$0.545	March 10, 2015	April 1, 2015
April 30, 2015	$0.545	June 10, 2015	July 1, 2015
July 30, 2015	$0.545	September 10, 2015	October 1, 2015

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

Electric Operations

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

	Second Quarter			Year to Date		
Millions of dollars	2015	Change	2014	2015	Change	2014
Operating revenues	$638.9	4.3 %	$612.4	$1,269.2	(1.8)%	$1,292.3
Less: Fuel used in generation	163.5	(23.1)%	212.7	338.1	(20.7)%	426.5
Purchased power	11.5	(29.4)%	16.3	24.3	(41.2)%	41.3
Margin	463.9	21.0 %	383.4	906.8	10.0 %	824.5
Other operation and maintenance expenses	121.7	2.9 %	118.3	241.0	0.3 %	240.3
Depreciation and amortization	76.4	2.6 %	74.5	152.3	2.4 %	148.7
Other taxes	48.9	3.4 %	47.3	98.0	3.8 %	94.4
Operating Income	$216.9	51.4 %	$143.3	$415.5	21.8 %	$341.1

Second Quarter

Margin increased due to downward adjustments of $60.1 million in 2014, compared to downward adjustments of $0.7 million in 2015, pursuant to orders of the SCPSC, related to fuel cost recovery and SCE&G’s DSM Programs. These adjustments were fully offset by the recognition, within other income, of gains realized upon the late 2013 settlement of certain derivative interest rate contracts and the application, as a reduction to operation and maintenance expenses, of a portion of SCE&G’s storm damage reserve, both of which had been deferred in regulatory accounts. Margin also increased due to base rate increases under the BLRA of $15.5 million and residential and commercial customer growth of $5.1 million. These increases were partially offset by lower industrial margins of $2.5 million. Operations and maintenance expenses increased due to the application of $5.0 million in 2014 of SCE&G’s storm damage reserve to offset downward revenue adjustments related to its DSM Programs and due to the amortization of $1.1 million of DSM Programs cost. These increases were partially offset by a decrease in labor of $1.1 million, primarily due to lower incentive compensation. Depreciation and amortization and other taxes increased due to net plant additions.

Year to Date

Margin increased due to downward adjustments of $60.1 million in 2014, compared to downward adjustments of $5.2 million in 2015, pursuant to orders of the SCPSC, related to fuel cost recovery and SCE&G’s DSM Programs. These adjustments were fully offset as described under Second Quarter. Margin also increased due to base rate increases under the BLRA of $31.5 million and residential and commercial customer growth of $9.2 million. These increases were partially offset by the effects of weather of $10.2 million, lower industrial margins of $6.6 million and lower collections under SCE&G's rate rider for pension costs of $3.0 million. Operations and maintenance expenses increased due to the application of $5.0 million in 2014 of SCE&G's storm damage reserve to offset downward revenue adjustments related to its DSM Programs and due to the amortization of $1.4 million of DSM Programs cost. These increases were partially offset by a decrease in labor of $4.8

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million primarily due to lower incentive compensation and lower pension costs as a result of lower rate rider collections, and lower storm expenses of $1.8 million. Depreciation and amortization and other taxes increased due to net plant additions.

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

	Second Quarter			Year to Date		
Classification	2015	Change	2014	2015	Change	2014
Residential	1,907	0.2 %	1,904	3,999	(1.4)%	4,055
Commercial	1,899	4.1 %	1,825	3,611	1.0 %	3,575
Industrial	1,599	3.7 %	1,542	3,066	2.4 %	2,994
Other	152	2.0 %	149	293	1.0 %	290
Total Retail Sales	5,557	2.5 %	5,420	10,969	0.5 %	10,914
Wholesale	237	0.9 %	235	483	0.8 %	479
Total Sales	5,794	2.5 %	5,655	11,452	0.5 %	11,393

Second Quarter and Year to Date

Retail sales volume increased primarily due to customer growth. Year to date volumes were partially offset by the effects of weather in the first quarter.

Gas Distribution

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

	Second Quarter			Year to Date		
Millions of dollars	2015	Change	2014	2015	Change	2014
Operating revenues	$130.5	(10.9)%	$146.4	$498.6	(17.1)%	$601.6
Less: Gas purchased for resale	59.2	(21.7)%	75.6	264.0	(28.3)%	368.1
Margin	71.3	0.7 %	70.8	234.6	0.5 %	233.5
Other operation and maintenance expenses	38.4	2.4 %	37.5	76.8	0.4 %	76.5
Depreciation and amortization	19.2	7.3 %	17.9	38.3	7.3 %	35.7
Other taxes	9.3	6.9 %	8.7	18.7	6.9 %	17.5
Operating Income	$4.4	(34.3)%	$6.7	$100.8	(2.9)%	$103.8

Second Quarter

Margin increased $1.4 million due primarily to residential and commercial customer growth, partially offset by a SCPSC-approved decrease in base rates under the RSA which became effective in November 2014 of $0.7 million. Operation and maintenance expenses increased primarily due to higher labor costs. Depreciation and amortization and other taxes increased due to net plant additions.

Year to Date

Margin increased primarily due to residential and commercial customer growth of $5.1 million and an industrial customer shift from interruptible to firm service of $1 million. These increases were partially offset by a SCPSC-approved decrease in base rates under the RSA which became effective in November 2014 of $2.5 million and decreases associated with franchise fee revenue of $2.3 million. Operation and maintenance expenses increased primarily due to higher labor costs. Depreciation and amortization and other taxes increased due to net plant additions.

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Sales volumes (in MMBTU) related to gas distribution margin by class, including transportation, were as follows:

	Second Quarter			Year to Date		
Classification (in thousands)	2015	Change	2014	2015	Change	2014
Residential	3,237	6.7 %	3,035	27,717	(4.5)%	29,015
Commercial	4,912	5.7 %	4,645	16,904	(2.9)%	17,412
Industrial	5,108	1.2 %	5,046	10,238	(1.4)%	10,379
Transportation	12,323	7.5 %	11,465	22,492	4.3 %	21,571
Total	25,580	5.7 %	24,191	77,351	(1.3)%	78,377

Second Quarter

Residential and commercial firm sales volumes increased due to residential and commercial customer growth, partially offset by the effects of weather and lower average use. Commercial and industrial interruptible volumes at SCE&G decreased due to customer usage. Industrial and transportation volumes at PSNC Energy increased due to industrial expansions. Transportation volumes at SCE&G increased due to customers shifting to transportation only service.

Year to Date

Residential and commercial firm sales volumes decreased due to the effects of weather and lower average use, partially offset by customer growth. Commercial and industrial interruptible volumes decreased due to customer usage and curtailments at SCE&G. Industrial and transportation volumes at PSNC Energy increased due to industrial expansions and lower curtailment activity. Transportation volumes at SCE&G increased due to customers shifting to transportation only service.

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 (loss) were as follows:

	Second Quarter			Year to Date		
Millions of dollars	2015	Change	2014	2015	Change	2014
Operating revenues	$71.4	(9.5)%	$78.9	$276.1	(7.7)%	$299.0
Net income (loss)	(5.5)	77.4 %	(3.1)	21.5	12.0 %	19.2

Second Quarter

Operating revenues decreased and net loss increased in the second quarter of 2015 primarily due to lower demand.

Year to Date

Operating revenues decreased in 2015 primarily due to lower demand. Net income increased in 2015 due to lower commodity costs and lower bad debt expense related primarily to lower revenues.

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	2015	Change	2014	2015	Change	2014
Operating revenues	$160.7	(33.2)%	$240.5	$382.1	(27.5)%	$527.3
Net income	3.1	*	1.1	8.7	13.0%	7.7

* Greater than 100%

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Second Quarter and Year to Date

Operating revenues decreased primarily due to lower market prices. Net income increased primarily due to lower transportation costs.

Other Operating Expenses

Other operating expenses were as follows:

	Second Quarter				Year to Date			
Millions of dollars	2015	Change		2014	2015	Change		2014
Other operation and maintenance	$172.7	(1.0	)%	$174.5	$345.2	(2.4	)%	$353.7
Depreciation and amortization	96.3	1.0	%	95.3	192.3	1.1	%	190.2
Other taxes	58.7	1.4	%	57.9	118.0	2.1	%	115.6

Changes in other operating expenses are largely attributable to the electric operations and gas distribution segments and are addressed in those discussions. In addition, for the second quarter and year to date, other operation and maintenance expense decreased by $6.0 million and $10.0 million, depreciation and amortization decreased by $2.1 million and $3.5 million and other taxes decreased by $1.4 million and $2.3 million, respectively, due to the sale of CGT in early 2015.

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. Other income and expense and AFC were as follows:

	Second Quarter				Year to Date			
Millions of dollars	2015	Change		2014	2015	Change		2014
Other Income	$18.9	(72.8	)%	$69.4	$37.3	(56.2	)%	$85.1
Other Expense	15.1	16.2	%	13.0	27.1	1.1	%	26.8
Allowance for Funds Used During Construction	6.6	(20.5	)%	8.3	11.7	(19.3	)%	14.5

Second Quarter

Other income decreased primarily due to the recognition of $55.1 million of gains in 2014, compared to $0.7 million in 2015, realized upon the settlement of certain interest rate derivative contracts previously recorded as regulatory liabilities pursuant to the SCPSC orders previously discussed. Such gain recognition was fully offset by downward adjustments to revenues reflected within electric margin and had no effect on net income (see electric margin discussion). Other income decreased by $5.4 million and other expenses decreased by $3.3 million due to the sale of SCI. AFC decreased due to lower AFC rates.

Year to Date

Other income decreased primarily due to the recognition of $55.1 million of gains in 2014, compared to $5.2 million in 2015, realized upon the settlement of certain interest rate derivative contracts previously recorded as regulatory liabilities pursuant to the SCPSC orders previously discussed. Such gain recognition was fully offset by downward adjustments to revenues reflected within electric margin and had no effect on net income (see electric margin discussion). Other income decreased by $7.1 million and other expenses decreased by $4.3 million due to the sale of SCI. AFC decreased due to lower AFC rates.

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Interest Expense

Interest charges increased primarily due to increased borrowings.

Income Taxes

Income taxes for the three and six months ended June 30, 2015 were higher than for the same periods in 2014 primarily due to higher income before taxes. Year to date income before taxes was higher in 2015 primarily due to the sales of CGT and SCI, and the year to date effective tax rate for 2015 was higher than the rate for 2014 primarily due to tax items directly associated with the sales of CGT and SCI.

LIQUIDITY AND CAPITAL RESOURCES

The Company anticipates that its cash obligations will be met through internally generated funds and additional short- and long-term borrowings. 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, 2015 was 5.75 and 4.42, 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 TD Bank N.A. The letters of credit expire, subject to renewal, in the fourth quarter of 2019.

At June 30, 2015, the Company had net available liquidity of approximately $1.6 billion, comprised of cash on hand and available amounts under lines of credit. The credit agreements total an aggregate of $1.8 billion, of which $200 million is scheduled to expire in October 2016 and the remainder is scheduled to expire in October 2019. 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 20 years at a weighted average effective interest rate of 5.8%. 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, banks, 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 $200 million outstanding with maturity dates of one year or less. The authority described herein will expire in October 2016.

On January 29, 2015, SCANA entered into an unsecured, three-month credit agreement in the amount of $150 million. SCANA entered this agreement to ensure sufficient liquidity was available to redeem its Junior Subordinated Notes on February 2, 2015. No borrowings were made under this agreement, and it expired according to its terms on February 6, 2015.

On February 2, 2015, SCANA redeemed prior to maturity $150 million of its 7.70% junior subordinated notes at their face value.

In May 2015, SCE&G issued $500 million of 5.1% first mortgage bonds due June 1, 2065. Proceeds from this sale were used 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.

SCANA issued approximately $14 million of common stock during January 2015 through various compensation and dividend reinvestment plans, after which the common stock needs of such plans have been met through open-market purchases.

SCE&G's current preliminary estimates of its capital expenditures for new nuclear construction (including transmission) for 2015 through 2017, which are subject to continuing review and adjustment, are $927 million in 2015, $979 million in 2016, and $899 million in 2017.

For additional information, see Note 4 to the consolidated financial statements.

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OTHER MATTERS

As Georgia's regulated provider, SCANA Energy provides service to low-income customers and customers unable to obtain or maintain natural gas service from other marketers at rates approved by the GPSC, and SCANA Energy receives funding from the Universal Service Fund to offset some of the bad debt associated with the low-income group. SCANA Energy's term as the regulated provider is scheduled to end on August 31, 2017.

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 - Interest rates on substantially all of the Company's outstanding long-term debt 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, including changes in the Company's market risk exposures relative to interest rate risk, see ITEM 2. MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS – LIQUIDITY AND CAPITAL RESOURCES and also Notes 2, 4, 6 and 7 of the condensed consolidated financial statements.

Commodity price risk - The Company uses derivative instruments to hedge forward purchases and sales of natural gas, which create market risks of different types. See Note 6 and 7 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	2015	2016	Options Purchased Call - Long	2015	2016
Settlement Price (a)	2.96	3.20	Strike Price (a)	3.79	3.66
Contract Amount (b)	9.6	9.0	Contract Amount (b)	16.1	21.7
Fair Value (b)	8.1	8.7	Fair Value (b)	0.3	1.3

Futures - Short	2015	2016
Settlement Price (a)	2.85	3.21
Contract Amount (b)	0.3	1.3
Fair Value (b)	0.2	1.3

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

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Swaps	Expected Maturity 2015	2016	2017	2018
Commodity Swaps:				
Pay fixed/receive variable (b)	37.6	37.4	6.7	3.7
Average pay rate (a)	3.6214	3.6932	4.1386	4.1974
Average received rate (a)	2.9578	3.1946	3.3863	3.4458
Fair value (b)	30.7	32.3	5.5	3.0
Pay variable/receive fixed (b)	20.9	22.1	5.0	2.9
Average pay rate (a)	2.9297	3.1828	3.3832	3.4446
Average received rate (a)	3.7505	3.8957	4.2114	4.2471
Fair value (b)	26.7	27.1	6.3	3.6
Basis Swaps:				
Pay variable/receive variable (b)	4.7	1.0	0.9	—
Average pay rate (a)	2.9223	3.2372	3.4231	—
Average received rate (a)	2.9077	3.2176	3.4320	—
Fair value (b)	4.7	1.0	0.9	—

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

ITEM 4. CONTROLS AND PROCEDURES

As of June 30, 2015, 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, 2015, 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, 2015 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
ITEM 1. FINANCIAL STATEMENTS
SOUTH CAROLINA ELECTRIC & GAS COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

Millions of dollars	June 30, 2015	December 31, 2014
Assets		
Utility Plant In Service	$10,732	$10,650
Accumulated Depreciation and Amortization	(3,679)	(3,667)
Construction Work in Progress	3,580	3,302
Plant to be Retired, Net	162	169
Nuclear Fuel, Net of Accumulated Amortization	316	329
Utility Plant, Net ($711 and $675 related to VIEs)	11,111	10,783
Nonutility Property and Investments:		
Nonutility property, net of accumulated depreciation	67	67
Assets held in trust, net-nuclear decommissioning	114	113
Other investments	2	2
Nonutility Property and Investments, Net	183	182
Current Assets:		
Cash and cash equivalents	24	100
Receivables, net of allowance for uncollectible accounts of $3 and $4	495	524
Affiliated receivables	24	109
Inventories (at average cost):		
Fuel and gas supply	120	131
Materials and supplies	135	129
Prepayments	124	154
Other current assets	23	99
Total Current Assets ($122 and $158 related to VIEs)	945	1,246
Deferred Debits and Other Assets:		
Pension asset	11	10
Regulatory assets	1,724	1,745
Other	182	141
Total Deferred Debits and Other Assets ($48 and $50 related to VIEs)	1,917	1,896
Total	$14,156	$14,107

See Notes to Condensed Consolidated Financial Statements.

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Millions of dollars	June 30, 2015	December 31, 2014
Capitalization and Liabilities		
Common Stock - no par value, 40.3 million shares outstanding	$2,756	$2,560
Retained Earnings	2,170	2,077
Accumulated Other Comprehensive Loss	(3)	(3)
Total Common Equity	4,923	4,634
Noncontrolling Interest	127	123
Total Equity	5,050	4,757
Long-Term Debt, net	4,790	4,299
Total Capitalization	9,840	9,056
Current Liabilities:		
Short-term borrowings	258	709
Current portion of long-term debt	10	10
Accounts payable	197	294
Affiliated payables	138	180
Customer deposits and customer prepayments	62	61
Taxes accrued	151	170
Interest accrued	67	64
Dividends declared	70	74
Derivative financial instruments	75	208
Other	62	99
Total Current Liabilities	1,090	1,869
Deferred Credits and Other Liabilities:		
Deferred income taxes, net	1,680	1,696
Deferred investment tax credits	26	28
Asset retirement obligations	537	536
Postretirement benefits	221	195
Regulatory liabilities	674	610
Other	88	117
Total Deferred Credits and Other Liabilities	3,226	3,182
Commitments and Contingencies (Note 9)	—	—
Total	$14,156	$14,107

See Notes to Condensed Consolidated Financial Statements.

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

Millions of dollars	Three Months Ended June 30, 2015	2014	Six Months Ended June 30, 2015	2014
Operating Revenues:				
Electric	$639	$612	$1,269	$1,292
Gas	70	86	212	265
Total Operating Revenues	709	698	1,481	1,557
Operating Expenses:				
Fuel used in electric generation	164	213	338	427
Purchased power	11	16	24	41
Gas purchased for resale	40	55	114	165
Other operation and maintenance	141	138	280	279
Depreciation and amortization	81	79	161	157
Other taxes	54	52	109	105
Total Operating Expenses	491	553	1,026	1,174
Operating Income	218	145	455	383
Other Income (Expense):				
Other income	9	59	18	62
Other expense	(7)	(7)	(14)	(13)
Interest charges, net of allowance for borrowed funds used during construction of $4, $4, $7 and $7	(60)	(56)	(120)	(112)
Allowance for equity funds used during construction	6	7	11	13
Total Other Income (Expense)	(52)	3	(105)	(50)
Income Before Income Tax Expense	166	148	350	333
Income Tax Expense	55	49	113	108
Net Income	111	99	237	225
Net Income Attributable to Noncontrolling Interest	(4)	(3)	(7)	(6)
Earnings Available to Common Shareholder	$107	$96	$230	$219
Dividends Declared on Common Stock	$70	$64	$140	$128

See Notes to Condensed Consolidated Financial Statements.

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

Millions of dollars	Three Months Ended June 30, 2015	2014	Six Months Ended June 30, 2015	2014
Net Income	$111	$99	$237	$225
Total Comprehensive Income	111	99	237	225
Comprehensive income attributable to noncontrolling interest	(4)	(3)	(7)	(6)
Comprehensive income available to common shareholder	$107	$96	$230	$219

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	2015	2014
Cash Flows From Operating Activities:		
Net income	$237	$225
Adjustments to reconcile net income to net cash provided from operating activities:		
Losses from equity method investments	2	3
Deferred income taxes, net	(16)	29
Depreciation and amortization	162	157
Amortization of nuclear fuel	27	20
Allowance for equity funds used during construction	(11)	(13)
Carrying cost recovery	(6)	(4)
Changes in certain assets and liabilities:		
Receivables	11	(22)
Inventories	(18)	(2)
Prepayments	39	(37)
Regulatory assets	174	(164)
Regulatory liabilities	45	(129)
Accounts payable	(18)	20
Taxes accrued	(19)	(136)
Interest accrued	3	1
Pension and other post retirement benefits	21	(3)
Derivative financial instruments	(133)	82
Other assets	(58)	20
Other liabilities	(61)	81
Net Cash Provided From Operating Activities	381	128
Cash Flows From Investing Activities:		
Property additions and construction expenditures	(520)	(452)
Proceeds from investments (including derivative collateral returned)	611	75
Purchase of investments (including derivative collateral posted)	(539)	(94)
Payments upon interest rate derivative contract settlement	(152)	(34)
Proceeds upon interest rate derivative contract settlement	10	—
Proceeds from investment in affiliate	80	—
Net Cash Used For Investing Activities	(510)	(505)
Cash Flows From Financing Activities:		
Proceeds from issuance of long-term debt	491	294
Repayment of long-term debt	(9)	(11)
Dividends	(145)	(126)
Contributions from parent	200	58
Return of capital to parent	(4)	(3)
Short-term borrowings –affiliate, net	(29)	51
Short-term borrowings, net	(451)	65
Net Cash Provided From Financing Activities	53	328
Net Decrease In Cash and Cash Equivalents	(76)	(49)
Cash and Cash Equivalents, January 1	100	92
Cash and Cash Equivalents, June 30	$24	$43

Supplemental Cash Flow Information:		
Cash paid for– Interest (net of capitalized interest of $7 and $7)	$108	$102
– Income taxes paid	89	127
– Income taxes received	(84)	—
Noncash Investing and Financing Activities:		
Accrued construction expenditures	80	101
Capital leases	4	2

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, 2015 and 2014
(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, 2014. 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 Entities

SCE&G has determined that it has a controlling financial interest in 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 $494 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

Subject to future developments in environmental regulations, among other matters, SCE&G expects to retire three units that are or were coal-fired by 2020. The net carrying value of these units is identified as Plant to be Retired, Net in the consolidated financial statements. SCE&G plans to request recovery of and a return on the net carrying value of these units in future rate proceedings in connection with their retirement, and expects that such deferred amounts will be recovered through rates. In the meantime, these units remain in rate base, and SCE&G depreciates them using composite straight-line rates approved by the SCPSC. The net carrying value of three previously retired units is recorded in regulatory assets within unrecovered plant (see Note 2).

New Accounting Matters

In May 2014, the FASB issued accounting guidance for revenue arising from contracts with customers that supersedes most current revenue recognition guidance, including industry-specific guidance. The new revenue recognition model provides a five-step analysis in determining when and how revenue is recognized, and will require revenue recognition to depict the transfer of promised goods or services to customers in an amount that reflects the consideration a company expects to receive in exchange for those goods or services. FASB has voted to delay the effective date of the revenue guidance by one year. As a result, Consolidated SCE&G is required to adopt this guidance in the first quarter of 2018 and early adoption is permitted beginning in the first quarter of 2017. Consolidated SCE&G has not determined the impact this guidance will have on its results of operations, cash flows or financial position.

In April 2015, the FASB issued accounting guidance intended to simplify the presentation of debt issuance costs by requiring that such costs be deducted from the carrying amounts related to debt liabilities when presented in the balance sheet.

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As permitted, Consolidated SCE&G expects to early adopt this guidance in the fourth quarter of 2015. Consolidated SCE&G does not expect the adoption of this guidance to have a significant impact on its financial position. The guidance will not affect Consolidated SCE&G's results of operations or cash flows.

In April 2015, the FASB issued accounting guidance related to fees paid by a customer in a cloud computing arrangement. Among other things, the guidance clarifies how to account for a software license element included in a cloud computing arrangement, and makes explicit that a cloud computing arrangement not containing a software license element should be accounted for as a service contract. Consolidated SCE&G expects to adopt this guidance in the first quarter of 2016. Consolidated SCE&G is evaluating this guidance and has not determined what impact it will have on its results of operations, cash flows or financial position.

In July 2015, the FASB issued accounting guidance intended to simplify the subsequent measurement of inventory cost by requiring most inventory to be measured at the lower of cost and net realizable value when presented in the balance sheet. Consolidated SCE&G expects to adopt this guidance in the first quarter of 2017. Consolidated SCE&G is evaluating this guidance and has not determined what impact it will have on its results of operations, cash flows or financial position.

2. RATE AND OTHER REGULATORY MATTERS

Rate Matters

Electric - Cost of Fuel

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 order dated April 29, 2014, the SCPSC approved a settlement agreement among SCE&G, the ORS, and the SCEUC in which SCE&G agreed to increase its base fuel cost component by approximately $10.3 million for the 12-month period beginning with the first billing cycle of May 2014. The base fuel cost increase was offset by a reduction in SCE&G's rate rider related to pension costs approved by the SCPSC in March 2014. In addition, pursuant to the April 29, 2014 order, SCE&G's electric revenue for 2014 was reduced by approximately $46 million for adjustments to the fuel cost component and related under-collected fuel balance. Such adjustments are fully offset by the recognition within other income of gains realized from the late 2013 settlement of certain interest rate derivatives which had been entered into in anticipation of the issuance of long-term debt, which gains had been deferred as a regulatory liability. The order also provided for the accrual of certain debt-related carrying costs on its under-collected balance of base fuel costs during the period May 1, 2014 through April 30, 2015. See also Note 6.

The cost of fuel includes amounts paid by SCE&G pursuant to the Nuclear Waste Act for the disposal of spent nuclear fuel. As a result of a November 2013 decision by the Court of Appeals, the DOE set the Nuclear Waste Act fee to zero effective May 16, 2014. The impact of changes to the Nuclear Waste Act fee is considered during annual fuel rate proceedings.

By order dated April 30, 2015, the SCPSC approved a settlement agreement among SCE&G, the ORS, and the SCEUC in which SCE&G agreed to decrease the total fuel cost component of its retail electric rates. Under this order, SCE&G is to recover an amount equal to its under-collected balance of base fuel and variable environmental costs as of April 30, 2015, over the subsequent 12-month period beginning with the first billing cycle of May 2015.

By order dated July 15, 2015, the SCPSC approved a settlement agreement among SCE&G, the ORS, the SCEUC and certain other parties concerning SCE&G's petition for approval to participate in a DER program and to recover DER program costs as a separate component of SCE&G's overall fuel factor. Under this order, SCE&G will, among other things, develop renewable energy facilities with a nameplate capacity of at least 84.5 MW by the end of 2020 and have at least 30 MW of utility-scale solar capacity in service by the end of 2016. The order also requires SCE&G to include bill incentives for solar energy generated by residential and commercial customers. SCE&G will also make bill incentives available for residential customers receiving solar power from community solar-programs.

Electric - Base Rates

In October 2013, SCE&G received an accounting order from the SCPSC directing it to remove from rate base deferred income tax assets arising from capital expenditures related to the New Units and to accrue carrying costs (recorded as a regulatory asset) on those amounts during periods in which they are not included in rate base. Such carrying costs are

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determined at SCE&G’s weighted average long-term debt borrowing rate. During the three and six months ended June 30, 2015, $2.2 million and $4.1 million, respectively, of such carrying cost were accrued within other income. During the three and six months ended June 30, 2014, $1.4 million and $2.5 million, respectively, of such carrying costs were accrued within other income. SCE&G anticipates that when the New Units are placed in service and accelerated tax deprecation is recognized on them, these deferred income tax assets will decline. When these assets are fully offset by related deferred income tax liabilities, the carrying cost accruals will cease, and the regulatory asset will begin to be amortized.

SCE&G files an IRP with the SCPSC annually which evaluates future electric generation needs based on a variety of factors, including customer energy demands, EPA regulations, reserve margins and fuel costs. SCE&G previously identified six coal-fired units that it has subsequently retired or intends to retire by 2020, subject to future developments in environmental regulations, among other matters. Three of these units were retired by December 31, 2013, and their net carrying value is recorded in regulatory assets as unrecovered plant and is being amortized over the units' previously estimated remaining useful lives as approved by the SCPSC. The net carrying value of the remaining units is included in Plant to be Retired, Net. 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.

In 2013, the SCPSC approved a suite of DSM Programs for development and implementation. Currently, SCE&G offers to its retail electric customers nine distinct programs which are designed to assist customers in reducing their demand for electricity and improving their energy efficiency. SCE&G submits annual filings to the SCPSC related to these programs which include actual program costs, net lost revenues both forecasted and actual), customer incentives, and net program benefits, among other things. As actual DSM Programs costs are incurred, they are deferred as regulatory assets (see Regulatory Assets and Regulatory Liabilities below) and recovered through a rate rider approved by the SCPSC. The rate rider also provides for recovery of net lost revenues and for a shared savings incentive. The SCPSC approved the following rate riders pursuant to the annual DSM Programs filings, which went into effect as indicated below:

Year	Effective	Amount	
2015	First billing cycle of May	$32.0	million
2014	First billing cycle of May	$15.4	million
2013	First billing cycle of May	$16.9	million

In April 2014, the SCPSC issued an order approving, among other things, SCE&G’s request to utilize approximately $17.8 million of the gains from the late 2013 settlement of certain interest rate derivative instruments, previously deferred as regulatory liabilities, to offset a portion of SCE&G’s DSM Programs rate rider. This order also allowed SCE&G to apply $5.0 million of its storm damage reserve and $5.0 million of the gains from the settlement of certain interest rate derivative instruments to offset previously deferred amounts.

Electric – BLRA

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. Through 2015, requested rate adjustments have been 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 recovery of the following amounts under the BLRA effective for bills rendered on and after October 30 in the following years:

Year	Action		Amount	
2014	2.8	% Increase	$66.2	million

2013	2.9	% Increase	$ 67.2	million

On May 29, 2015, SCE&G filed its annual request for approval of revised rates under the provisions of the BLRA. On July 30, 2015, ORS filed a report of its review of SCE&G's request. ORS proposes that SCE&G be allowed to increase its retail rates in the amount of $64.5 million or 2.6%. If approved, the rate change would be effective for bills rendered on and after October 30, 2015.

On March 12, 2015, SCE&G petitioned the SCPSC seeking approval of an updated construction milestone schedule and capital cost schedule for the New Units. The updated construction schedule reflects new substantial completion dates for Units 2 and 3 of June 2019, and June 2020, respectively. The petition also incorporates in the construction cost schedules approximately $698 million (SCE&G’s portion in 2007 dollars) in incremental capital costs that have been identified since the

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last approved order in November 2012, of which $539 million (SCE&G's portion in 2007 dollars) are associated with construction delays and other contested costs. The total project capital cost is now estimated at approximately $5.2 billion (SCE&G's portion in 2007 dollars) or $6.8 billion including escalation and allowance for funds used during construction (SCE&G's portion in future dollars). As noted in the petition, the construction and capital cost schedules are subject to continuing review and negotiations by the parties. In making this filing, SCE&G does not waive any claims related to delay and other related contested costs with the Consortium.

On June 29, 2015, SCE&G entered into a settlement agreement with the ORS and the SCEUC (one of three non-ORS intervenors) related to the petition to update construction and capital schedules for the New Units. Under this agreement, all settling parties agree to the revised construction and capital cost schedules as outlined in the petition filed with the SCPSC on March 12, 2015. Further, the settling parties agreed to revise the return on common equity for the new nuclear project from 11.0% to 10.5%, for purposes of calculating revised rates under the BLRA, beginning on and after January 1, 2016. The revised rate of return on common equity will remain in effect until the New Units are completed. The settlement agreement is subject to approval by the SCPSC. A public hearing on this matter was held in July 2015, and the SCPSC is expected to issue its order in September 2015. See Note 9.

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 following years:

Year	Action		Amount	
2014	0.6	% Decrease	$2.6	million
2013	No change		-	

On June 15, 2015, SCE&G submitted its annual RSA filing with the SCPSC for the 12-month period ending March 31, 2015. 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 that provides for the recovery of actual gas costs incurred, including transportation costs. 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, and its gas purchasing policies and practices are reviewed annually by the SCPSC. The annual review conducted for the 12-month period ended July 31, 2014 resulted in the SCPSC issuing an order finding that SCE&G's gas purchasing policies and practices during the review period were reasonable and prudent.

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. Other than unrecovered plant, 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.

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Millions of dollars	June 30, 2015	December 31, 2014
Regulatory Assets:		
Accumulated deferred income taxes	$277	$278
Under collections – electric fuel adjustment clause	—	20
Environmental remediation costs	35	36
AROs and related funding	353	347
Franchise agreements	24	26
Deferred employee benefit plan costs	300	310
Planned major maintenance	—	2
Deferred losses on interest rate derivatives	455	453
Deferred pollution control costs	35	36
Unrecovered plant	131	137
DSM Programs	59	56
Carrying costs on deferred tax assets related to nuclear construction	13	9
Other	42	35
Total Regulatory Assets	$1,724	$1,745
Regulatory Liabilities:		
Accumulated deferred income taxes	$16	$17
Asset removal costs	514	505
Storm damage reserve	6	6
Deferred gains on interest rate derivatives	123	82
Planned major maintenance	15	—
Total Regulatory Liabilities	$674	$610

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 which are expected to be recovered in retail electric rates over periods exceeding 12 months.

Environmental remediation costs represent costs associated with the assessment and clean-up of sites currently or formerly owned by SCE&G and are expected to be recovered over periods of up to approximately 24 years.

ARO and related funding represents the regulatory asset associated with the legal obligation to decommission and dismantle Summer Station and conditional AROs related to generation, transmission and distribution properties, including gas pipelines. 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 is recovering these amounts through cost of service rates through approximately 2021.

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 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. Accordingly, in 2013 SCE&G began recovering through utility rates approximately $63 million of deferred pension costs for electric operations over approximately 30 years and approximately $14 million of deferred pension costs for gas operations over approximately 14 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.

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Planned major maintenance related to certain fossil fueled turbine/generation equipment and nuclear refueling outages is accrued in periods other than when incurred, pursuant to specific SCPSC orders. SCE&G collects and accrues $18.4 million annually for fossil fueled turbine/generation equipment maintenance and collects and accrues $17.2 million annually for nuclear-related refueling charges.

Deferred losses or gains on interest rate derivatives represent (i) the effective portions of changes in fair value and payments made or received upon settlement of certain interest rate derivatives designated as cash flow hedges and (ii) the changes in fair value and payments made or received upon settlement of certain other interest rate derivatives not so designated. The amounts recorded with respect to (i) are expected to be amortized to interest expense over the lives of the underlying debt through 2043. The amounts recorded with respect to (ii) are expected to be similarly amortized to interest expense over periods up to approximately 50 years except when, in the case of deferred gains, such amounts are applied otherwise at the direction of the SCPSC.

Deferred pollution control costs represent deferred depreciation and operating and maintenance costs associated with the scrubbers installed at certain coal-fired generating plants pursuant to specific regulatory orders. Such costs are being recovered through utility rates through 2045.

Unrecovered plant represents the carrying value of coal-fired generating units, including related materials and supplies inventory, retired from service prior to being fully depreciated. Pursuant to SCPSC approval, SCE&G is amortizing these amounts through cost of service rates over the units' previous estimated remaining useful lives through 2025. Unamortized amounts are included in rate base and are earning a current return.

DSM Programs represent deferred costs associated with such programs. As a result of an April 2015 SCPSC order, deferred costs are currently being recovered over approximately five years through an approved rate rider.

Carrying costs on deferred tax assets related to nuclear construction represent accrued carrying costs on accumulated deferred income tax assets associated with the New Units which are not part of electric base rates. These carrying costs are computed using weighted average long-term debt cost of capital and will be amortized over ten years beginning in approximately 2021.

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. During the six months ended June 30, 2015, no amounts were applied to offset incremental storm damage costs.

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 specifically 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, 2015 and 2014 were as follows:

	Common Stock		Retained	Accumulated Other Comprehensive	Noncontrolling	Total
Millions	Shares	Amount	Earnings	Income (Loss)	Interest	Equity
Balance at January 1, 2015	40	$2,560	$2,077	$ (3)	$ 123	$4,757
Earnings available to common shareholder			230		7	237
Deferred cost of employee benefit plans				—		—
Total Comprehensive Income			230	—	7	237
Capital contributions from parent		196				196
Cash dividend declared			(137)		(3)	(140)
Balance at June 30, 2015	40	$2,756	$2,170	$ (3)	$ 127	$5,050
Balance at January 1, 2014	40	$2,479	$1,896	$ (3)	$ 117	$4,489
Earnings available to common shareholder			219		6	225
Deferred cost of employee benefit plans				—		—
Total Comprehensive Income			219	—	6	225
Capital contributions from parent		55				55
Cash dividend declared			(125)		(3)	(128)
Balance at June 30, 2014	40	$2,534	$1,990	$ (3)	$ 120	$4,641

SCE&G had 50 million shares of common stock authorized as of June 30, 2015 and December 31, 2014. SCE&G had 20 million shares of preferred stock authorized as of June 30, 2015 and December 31, 2014, of which 1,000 shares at a stated value of $100,000 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 May 2014, SCE&G issued $300 million of 4.5% first mortgage bonds due June 1, 2064. Proceeds from this sale were used 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 May 2015, SCE&G issued $500 million of 5.1% first mortgage bonds due June 1, 2065. Proceeds from this sale were used 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.

Substantially all electric utility plant is pledged as collateral in connection with long-term debt.

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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, 2015		December 31, 2014	
Lines of credit:				
Total committed long-term	$1,400		$1,400	
Outstanding commercial paper (270 or fewer days)	$258		$709	
Weighted average interest rate	0.46	%	0.52	%
Letters of credit supported by LOC	$0.3		$0.3	
Available	$1,142		$691	

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 2019. In addition, SCE&G is a party to a three-year credit agreement in the amount of $200 million, which expires in October 2016. 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 TD Bank N.A. These letters of credit expire, subject to renewal, in the fourth quarter of 2019.

Consolidated SCE&G participates in a utility money pool with SCANA and certain other subsidiaries of SCANA. Money pool borrowings and investments bear interest at short-term market rates. Consolidated SCE&G's interest income and expense from money pool transactions were not significant for any period presented. At June 30, 2015, Consolidated SCE&G had outstanding money pool borrowings due to an affiliate of $54.0 million. At December 31, 2014, Consolidated SCE&G had outstanding money pool borrowings due to an affiliate of $83.0 million and money pool investments due from an affiliate of $80.0 million.

5. INCOME TAXES

During 2013 and 2014, SCANA amended certain of its tax returns to claim certain tax-defined research and development deductions and credits. In connection with these filings, Consolidated SCE&G recorded an unrecognized tax benefit of $16 million. If recognized, $13 million of the tax benefit would affect Consolidated SCE&G's effective tax rate. It is reasonably possible that this tax benefit will increase by an additional $2 million within the next 12 months. It is also reasonably possible that this tax benefit may decrease by $7 million within the next 12 months. No other material changes in the status of Consolidated SCE&G's tax positions have occurred through June 30, 2015.

Consolidated SCE&G recognizes interest accrued related to unrecognized tax benefits within interest expense and recognizes tax penalties within other expenses. Because no refunds related to the unrecognized tax benefits have yet been received, Consolidated SCE&G has not recorded any interest expense or penalties associated with them.

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 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 their 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 locks or forward starting swap agreements. Pursuant to regulatory orders, interest rate derivatives entered into by SCE&G after October 2013 are not designated as cash flow hedges, and all related fair value changes and settlement amounts are recorded as regulatory assets or liabilities. Interest rate derivatives entered into before October 2013 were designated as cash flow hedges, and for such instruments only the effective portion of fair value changes and settlement amounts are recorded in regulatory assets or regulatory liabilities. Upon settlement, losses on swaps are amortized over the lives of related debt issuances, and gains are applied to under-collected fuel, are amortized to interest expense or are applied as otherwise directed by the SCPSC.

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

GENCO was party to an interest rate swap designated as a cash flow hedge with a notional amount of $36.4 million at June 30, 2015 and $36.4 million at December 31, 2014. SCE&G was party to interest rate swaps not designated as cash flow hedges with an aggregate notional amount of $835.0 million at June 30, 2015 and $1.1 billion at December 31, 2014, respectively.

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	
	Balance Sheet	Fair	Balance Sheet	Fair
Millions of dollars	Location	Value	Location	Value
As of June 30, 2015				

Designated as hedging instruments				
Interest rate contracts			Derivative financial instruments	$1
			Other deferred credits and other liabilities	7
Total				$8
Not designated as hedging instruments				
Interest rate contracts	Other deferred debits and other assets	$41	Derivative financial instruments	$74
			Other deferred credits and other liabilities	12
Total		$41		$86
As of December 31, 2014				
Designated as hedging instruments				
Interest rate contracts			Derivative financial instruments	$1
			Other deferred credits and other liabilities	8
Total				$9
Not designated as hedging instruments				
Interest rate contracts			Derivative financial instruments	$207
			Other deferred credits and other liabilities	17
Total				$224

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

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	2015	2014	Location	2015	2014
Three Months Ended June 30,					
Interest rate contracts	$2	$(1)	Interest expense	$(1)	—
Six Months Ended June 30,					
Interest rate contracts	—	$(4)	Interest expense	$(1)	$(1)

As of June 30, 2015, Consolidated SCE&G expects that during the next 12 months reclassifications from regulatory accounts to earnings arising from cash flow hedges designated as hedging instruments will include approximately $2.3 million as an increase to interest expense, assuming financial markets remain at their current levels.

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, 2015 and 2014, respectively.

Derivatives not designated as Hedging Instruments

	Gain (Loss) Deferred in Regulatory Accounts			Gain Reclassified from Deferred Accounts into Income	
Millions of dollars	2015	2014	Location	2015	2014
Three Months Ended June 30,					
Interest rate contracts	$132	$(73)	Other income	$1	$55
Six Months Ended June 30,					
Interest rate contracts	$37	$(185)	Other income	$5	$55

As of June 30, 2015, Consolidated SCE&G expects that during the next 12 months reclassifications from regulatory accounts to earnings arising from derivatives not designated as hedges will include $0.5 million as an increase to interest expense.

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. 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, 2015 and December 31, 2014, Consolidated SCE&G has posted $30.1 million and $107.1 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 Other Current Assets on the condensed consolidated balance sheets. Collateral related to noncurrent positions is recorded in Other within Deferred Debits and Other Assets on the condensed consolidated balance sheets. If all of the contingent features underlying these instruments had been fully triggered as of June 30, 2015 and December 31, 2014, Consolidated SCE&G could have been required to post an additional $46.1 million and $125.9 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, 2015 and December 31, 2014 is $76.2 million and $233.0 million, respectively.

In addition, as of June 30, 2015 and December 31, 2014, 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 had been fully triggered as of June 30, 2015 and December 31, 2014, Consolidated SEC&G could request $23.0 million and $- 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, 2015 and December 31, 2014 is $23.0 million and $- million, respectively.

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

	Gross Amounts of Recognized	Gross Amounts Offset in the	Net Amounts Presented in the	Gross Amounts Not Offset in the Statement	Net Amount

Millions of dollars	Assets	Statement of Financial Position	Statement of Financial Position	of Financial Position Financial Instruments	Cash Collateral Received	
As of June 30, 2015						
Interest rate contracts	$41	—	$41	$(18)	—	$23
Balance Sheet Location	Other deferred debits and other assets		$41			

As of December 31, 2014, Consolidated SCE&G had no derivative assets.

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		Net Amount
				Financial Instruments	Cash Collateral Posted	
As of June 30, 2015						
Interest rate contracts	$94	—	$94	$(18)	$(30)	$46
Balance Sheet Location	Derivative financial instruments		$75			
	Other deferred credits and other liabilities		19			
	Total		$94			
As of December 31, 2014						
Interest rate contracts	$233	—	$233	—	$(107)	$126
Balance Sheet Location	Derivative financial instruments		$208			
	Other deferred credits and other liabilities		25			
	Total		$233			

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 Level 2 measurements were as follows:

Millions of dollars		June 30, 2015	December 31, 2014
Assets -	Interest rate contracts	$41	—
Liabilities -	Interest rate contracts	94	$233

There were no Level 1 or Level 3 fair value measurements for either period presented, and there were no transfers of fair value amounts into or out of Levels 1, 2 or 3 during the periods presented.

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Financial instruments for which the carrying amount may not equal estimated fair value were as follows:

Millions of dollars	June 30, 2015 Carrying Amount	June 30, 2015 Estimated Fair Value	December 31, 2014 Carrying Amount	December 31, 2014 Estimated Fair Value
Long-term debt	$4,800.6	$5,191.5	$4,308.6	$5,070.9

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

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

	Pension Benefits		Other Postretirement Benefits	
Millions of dollars	2015	2014	2015	2014
Three months ended June 30,				
Service cost	$4.6	$4.0	$1.1	$1.0
Interest cost	8.0	8.6	2.3	2.4
Expected return on assets	(13.0)	(14.1)	—	—
Prior service cost amortization	0.8	0.8	0.1	0.1
Amortization of actuarial losses	3.0	1.1	0.4	0.1
Net periodic benefit cost	$3.4	$0.4	$3.9	$3.6
Six months ended June 30,				
Service cost	$9.2	$8.0	$2.2	$2.0
Interest cost	16.0	17.2	4.6	4.8
Expected return on assets	(26.1)	(28.3)	—	—
Prior service cost amortization	1.7	1.7	0.1	0.2
Amortization of actuarial losses	6.0	2.2	0.9	0.2
Net periodic benefit cost	$6.8	$0.8	$7.8	$7.2

No significant contribution to the pension trust is expected for the foreseeable future, nor is a limitation on benefit payments expected to apply. SCE&G recovers current pension costs through either a rate rider that may be adjusted annually for retail electric operations or through cost of service rates for gas operations.

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 SCE&G's nuclear power plant. Price-Anderson provides funds up to $12.9 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 $127.3 million per reactor owned for each nuclear incident occurring at any reactor in the United States, provided that not more than $18.9 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 $84.8 million per incident, but not more than $12.6 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 resulting from an event of nuclear origin. 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 $45.9 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, 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 Consolidated SCE&G’s results of operations, cash flows and financial position.

New Nuclear Construction

In 2008, SCE&G, on behalf of itself and as agent for Santee Cooper, contracted with the Consortium for the design and construction of the New Units at the site of Summer Station.

SCE&G's current ownership share in the New Units is 55%. As discussed below, under an agreement signed in January 2014 (and subject to customary closing conditions, including necessary regulatory approvals), SCE&G has agreed to acquire an additional 5% ownership in the New Units from Santee Cooper.

EPC Contract and BLRA Matters

The construction of the New Units and SCE&G’s related recovery of financing costs through rates is subject to review and approval by the SCPSC as provided for in the BLRA. Under the BLRA, the SCPSC has approved, among other things, a milestone schedule and a capital costs estimates schedule for the New Units. This approval constitutes a final and binding determination that the New Units are used and useful for utility purposes, and that the capital costs associated with the New Units are prudent utility costs and expenses and are properly included in rates, so long as the New Units are constructed or are being constructed within the parameters of the approved milestone schedule, including specified schedule contingencies, and the approved capital costs estimates schedule. Subject to the same conditions, the BLRA provides that SCE&G may apply to the SCPSC annually for an order to recover through revised rates SCE&G’s weighted average cost of capital applied to all or part of the outstanding balance of construction work in progress concerning the New Units. Such annual rate changes are described in Note 2. As of June 30, 2015, SCE&G’s investment in the New Units totaled $3.0 billion, for which the financing costs on $2.4 billion have been reflected in rates under the BLRA.

The SCPSC granted initial approval of the construction schedule, including 146 milestones within that schedule, and related forecasted capital costs in 2009. The NRC issued COLs in March 2012. In November 2012, the SCPSC approved an updated milestone schedule and additional updated capital costs for the New Units. In addition, the

SCPSC approved revised substantial completion dates for the New Units based on that March 2012 issuance of the COL and the amounts agreed upon by SCE&G and the Consortium in July 2012 to resolve known claims by the Consortium for costs related to COL delays, design modifications of the shield building and certain prefabricated structural modules for the New Units and unanticipated rock conditions at the site. In October 2014, the South Carolina Supreme Court affirmed the SCPSC's order on appeal.

The substantial completion dates currently approved by the SCPSC for Units 2 and 3 are March 15, 2017 and May 15, 2018. The SCPSC also approved an 18-month contingency period beyond each of these dates, and for each of the 146 milestones in the schedule. A petition requesting revisions to these dates is discussed below.

Since the settlement of delay-related claims in 2012, the Consortium has continued to experience delays in the schedule, including those related to fabrication and delivery of sub-modules for the New Units. The fabrication and delivery of sub-modules have been and remain focus areas of the Consortium. Shield building panels are considered critical path items for both New Units, and the current schedule for production of such panels will require mitigation to support the updated substantial completion dates (see below). The sub-modules for CA01, which houses components inside the containment vessel, were delivered, and its on-site fabrication was completed such that CA01 was placed on the nuclear island of Unit 2 on July 23, 2015.

During the fourth quarter of 2013, the Consortium began a full re-baselining of the Unit 2 and Unit 3 construction schedules to incorporate a more detailed evaluation of the engineering and procurement activities necessary to accomplish the schedules and to provide a detailed reassessment of the impact of the revised Unit 2 and Unit 3 schedules on engineering and design resource allocations, procurement, construction work crew efficiencies, and other items. The result was a revised, fully integrated project schedule with timing of specific construction activities (Revised, Fully-Integrated Construction Schedule) along with related cost information.

The Revised, Fully-Integrated Construction Schedule indicated that the substantial completion of Unit 2 was expected to occur in mid-June 2019 and that the substantial completion of Unit 3 was expected to be approximately 12 months later. SCE&G has not, however, accepted the Consortium's contention that the new substantial completion dates are made necessary by delays that are excusable under the EPC Contract. The Consortium continues to refine and update the Revised, Fully-Integrated Construction Schedule as designs are finalized, as construction progresses, and as additional information is received.

As discussed above, the milestone schedule approved by the SCPSC in November 2012 provides for 146 milestone dates, each of which is subject to an 18-month schedule contingency. As of June 30, 2015, 106 milestones have been completed, and three of the remaining milestones have not been completed within their 18-month contingency periods. In light of the Revised, Fully-Integrated Schedule, it is anticipated that the completion dates for a substantial number of the remaining milestone dates will also extend beyond their contingency periods. Further, capital costs (in 2007 dollars) and gross construction cost estimates (including escalation and AFC) are projected to exceed amounts currently approved by the SCPSC of $4.5 billion and $5.8 billion, respectively.

As such, in March 2015 SCE&G petitioned the SCPSC for an order to update the BLRA milestone schedule based on revised substantial completion dates for Units 2 and 3 of June 2019 and June 2020, respectively, each subject to an 18-month contingency period. In addition, that petition included certain updated owner's costs ($245 million) and other capital costs ($453 million) which, if approved, would reset projected capital costs (in 2007 dollars) and gross construction cost estimates (including escalation and AFC) to $5.2 billion and $6.8 billion, respectively. These projections include cost amounts related to the Revised, Fully-Integrated Construction Schedule for which SCE&G has not accepted responsibility and which may be the subject of dispute. As such, the petition does not reflect the resolution of negotiations.

In June 2015, SCE&G entered into a settlement agreement with ORS and the SCEUC (one of three non-ORS intervenors) in which the settling parties agreed to support approval of the revised construction and capital cost schedules and agreed to revise the allowed return on equity for new nuclear construction from 11.00% to 10.50% applied prospectively for the purpose of calculating revised rates sought by SCE&G under the BLRA on and after January 1, 2016, until such time as the New Units are completed. This settlement agreement among SCE&G, ORS and the SCEUC is subject to approval by the SCPSC.

The SCPSC held a public hearing related to the petition and the settlement agreement in July 2015. While the BLRA provides that the SCPSC shall grant the petition for modification if the record justifies a finding that the change is not the result of imprudence by SCE&G, SCE&G cannot predict the outcome of this regulatory process. As described in Note 2, SCE&G expects the SCPSC to issue its order on the petition and the settlement agreement in September 2015.

Additional claims by the Consortium or SCE&G involving the project schedule and budget may arise as the project continues. The parties to the EPC Contract have established both informal and formal dispute resolution procedures in order to resolve such issues. SCE&G expects to resolve all disputes (including any ultimate disagreements involving the preliminary cost estimates provided by the Consortium in the third quarter of 2014) through both the informal and formal procedures and anticipates that any costs that arise through such dispute resolution processes, as well as other costs identified from time to time, will be recoverable through rates.

Santee Cooper Matters

As noted above, SCE&G has agreed to acquire an additional 5% ownership in the New Units from Santee Cooper. Under the terms of this agreement, SCE&G will acquire a 1% ownership interest in the New Units at the commercial operation date of Unit 2, an additional 2% ownership interest no later than the first anniversary of such commercial operation date, and the final 2% no later than the second anniversary of such commercial operation date. SCE&G has agreed to pay an amount equal to Santee Cooper's actual cost of the percentage conveyed as of the date of each conveyance. In addition, the agreement

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provides that Santee Cooper will not transfer any of its remaining interest in the New Units to third parties until the New Units are complete. This transaction will not affect the payment obligations between the parties during construction for the New Units, nor is it anticipated that the payments for the additional ownership interest would be reflected in a revised rates filing under the BLRA. Based on the current milestone schedule and capital costs schedule approved by the SCPSC in November 2012, SCE&G's estimated cost would be approximately $500 million for the additional 5% interest being acquired from Santee Cooper. This cost figure is expected to be higher in light of the delays and related costs and regulatory petition discussed above.

Nuclear Production Tax Credits

The IRS has notified SCE&G that, subject to a national megawatt capacity limitation, the electricity to be produced by each of the New Units (advanced nuclear units, as defined) would qualify for nuclear production tax credits under Section 45J of the Internal Revenue Code to the extent that such New Unit is operational before January 1, 2021 and other eligibility requirements are met. These nuclear production tax credits (related to SCE&G's 55% share of both New Units) could total as much as approximately $1.4 billion. Such credits would be earned over the first eight years of each New Unit's operations and would be realized by SCE&G over those years or during allowable carry-forward periods. Based on the above substantial completion dates provided by the Consortium of June 2019 and June 2020 for Units 2 and 3, respectively, both New Units are expected to be operational and to qualify for the nuclear production tax credits; however, further delays in the schedule or changes in tax law could impact such conclusions. To the extent that production tax credits are realized, their benefits are expected to be provided directly to SCE&G's electric customers as so realized.

Other Project Matters

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. SCE&G prepared and submitted an integrated response plan for the New Units to the NRC in August 2013. That plan is currently under review by the NRC and SCE&G does not anticipate any additional regulatory actions as a result of that review, but it cannot predict future regulatory activities or how such initiatives would impact construction or operation of the New Units.

Environmental

Consolidated SCE&G's operations are subject to extensive regulation by various federal and state authorities in the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes. Applicable statutes and rules include the CAA, CWA, Nuclear Waste Act and CERCLA, among others. In many cases, regulations proposed by such authorities could have a significant impact on Consolidated SCE&G's financial condition, results of operations and cash flows. In addition, Consolidated SCE&G often cannot predict what conditions or requirements will be imposed by regulatory or legislative proposals. To the extent that compliance with environmental regulations or legislation results in capital expenditures or operating costs, Consolidated SCE&G expects to recover such expenditures and costs through existing ratemaking provisions.

From a regulatory perspective, SCE&G and GENCO continually monitor and evaluate their current and projected emission levels and strive to comply with all state and federal regulations regarding those emissions. SCE&G and GENCO participate in the sulfur dioxide and nitrogen oxide emission allowance programs with respect to coal plant emissions and also have constructed additional pollution control equipment at several larger coal-fired electric generating plants. Further, SCE&G is engaged in construction activities of the New Units which are expected to reduce GHG emission levels significantly once they are completed and dispatched by potentially displacing some of the current coal-fired generation sources. These actions are expected to address many of the rules and regulations discussed herein.

The EPA issued a revised carbon standard for new power plants by re-proposing NSPS under the CAA for emissions of carbon dioxide (CO_2) from newly constructed fossil fuel-fired units. The final rule was issued on August 3, 2015 and requires all new coal-fired power plants to meet a carbon emission rate of 1,400 pounds CO_2 per MWh and new natural gas units to meet 1,000 pounds CO_2 per MWh. While most new natural gas plants will not be required to include any new technologies, no new coal-fired plants could be constructed without partial carbon capture and sequestration capabilities. SCE&G and GENCO are evaluating the final rule, but do not plan to construct new coal-fired units in the foreseeable future. In addition, on August 3, 2015, the EPA issued its final rule on emission guidelines for states to follow in developing plans to address GHG emissions from existing units. The rule includes state-specific goals for reducing national carbon dioxide emissions by 32% from 2005 levels by 2030. The rule also provides for nuclear reactors under construction, such as the New

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Units, to count towards compliance and establishes a phased-in compliance approach beginning in 2022. Consolidated SCE&G is currently evaluating the rule and expects any costs incurred to comply with such rule to be recoverable through rates.

In July 2011, the EPA issued the CSAPR to reduce emissions of sulfur dioxide and nitrogen oxide from power plants in the eastern half of the United States. A series of court actions stayed this rule until October 23, 2014, when the Court of Appeals granted a motion to lift the stay. On December 3, 2014, the EPA published an interim final rule that aligns the dates in the CSAPR text with the revised court-ordered schedule, thus delaying the implementation dates to 2015 for Phase 1 and to 2017 for Phase 2. The CSAPR replaces the CAIR and requires a total of 28 states to reduce annual sulfur dioxide emissions and annual or ozone season nitrogen oxide emissions to assist in attaining the ozone and fine particle NAAQS. The rule establishes an emissions cap for sulfur dioxide and nitrogen oxide and limits the trading for emission allowances by separating affected states into two groups with no trading between the groups. On July 28, 2015, the Court of Appeals held that Phase 2 emissions budgets for certain states, including South Carolina, required reductions in emissions beyond the point necessary to achieve downwind attainment and were, therefore, invalid. The Court of Appeals remanded CSAPR, without vacating the rule, to the EPA for further consideration. The opinion of the Court of Appeals has no immediate impact on SCE&G and GENCO or their generation operations. Air quality control installations that SCE&G and GENCO have already completed have positioned them to comply with the existing allowances set by the CSAPR. Any cost incurred to comply with CSAPR are expected to be recoverable through rates.

In April 2012, the EPA's MATS rule containing new standards for mercury and other specified air pollutants became effective. The rule provides up to four years for generating facilities to meet the standards, and SCE&G and GENCO's evaluation of the rule is ongoing. SCE&G's decision to retire certain coal-fired units or convert them to burn natural gas (see Note 1) and its project to build the New Units along with other actions are expected to result in SCE&G's compliance with MATS. On November 19, 2014, the EPA finalized its reconsideration of certain provisions applicable during startup and shutdown of generating facilities. SCE&G and GENCO have received a one year extension (until April 2016) to comply with MATS at Cope, McMeekin, Wateree and Williams Stations. These extensions will allow time to convert McMeekin Station to burn natural gas and to install additional pollution control devices at the other plants that will enhance the control of certain MATS-regulated pollutants. On June 29, 2015, the U.S. Supreme Court ruled that the EPA unreasonably failed to consider costs in its decision to regulate, and remanded a case challenging the regulation on that basis to the Court of Appeals for the D.C. Circuit. The ruling, however, is not expected to have an impact on SCE&G or GENCO due to the aforementioned retirements and conversions.

The CWA provides for the imposition of effluent limitations that require treatment for wastewater discharges. Under the CWA, compliance with applicable limitations is achieved under state-issued NPDES permits. As a facility’s NPDES permit is renewed (every five years), any new effluent limitations would be incorporated. The ELG Rule was published in the Federal Register on June 7, 2013, and is expected to be finalized no later than September 30, 2015. Once the rule becomes effective, state regulators will modify facility NPDES permits to match more restrictive standards, thus requiring facilities to retrofit with new wastewater treatment technologies. Compliance dates will vary by type of wastewater, and some will be based on a facility's five year permit cycle and thus may range from 2018 to 2023. Based on the proposed rule, Consolidated SCE&G expects that wastewater treatment technology retrofits will be required at Williams and Wateree Stations and may be required at other facilities.

The CWA Section 316(b) Existing Facilities Rule became effective in October 2014. This rule establishes national requirements for the location, design, construction and capacity of cooling water intake structures at existing facilities that reflect the best technology available for minimizing the adverse environmental impacts of impingement and entrainment. SCE&G and GENCO are conducting studies and implementing plans to ensure compliance with this rule. In addition, Congress is expected to consider further amendments to the CWA. Such legislation may include toxicity-based standards as well as limitations to mixing zones.

On April 17, 2015, the EPA's final rule for CCR was published in the Federal Register and will become effective in the fourth quarter of 2015. This rule regulates CCR as a non-hazardous waste under Subtitle D of the Resource Conservation and Recovery Act and imposes certain requirements on ash storage ponds at SCE&G's and GENCO's coal-fired generating facilities. Although the full effects of this rule are still being evaluated, SCE&G and GENCO have already closed or have begun the process of closure of all of their ash storage ponds and have previously recognized AROs for such ash storage ponds under existing requirements. Consolidated SCE&G does not expect the incremental compliance costs associated with this rule to be significant and expects to recover such costs in future rates.

The Nuclear Waste Act required that the United States government accept and permanently dispose of high-level radioactive waste and spent nuclear fuel by January 31, 1998, and it also imposed on utilities the primary responsibility for storage of their spent nuclear fuel until the repository is available. SCE&G entered into a Standard Contract for Disposal of

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Spent Nuclear Fuel and/or High-Level Radioactive Waste with the DOE in 1983. As of June 30, 2015, the federal government has not accepted any spent fuel from Summer Station Unit 1, and it remains unclear when the repository may become available. SCE&G has on-site spent nuclear fuel storage capability in its existing fuel pool until at least 2017 and is constructing a dry cask storage facility to accommodate the spent nuclear fuel output for the life of Summer Station Unit 1. SCE&G may evaluate other technology as it becomes available.

The provisions of CERCLA authorize the EPA to require the clean-up of hazardous waste sites. The state of South Carolina has similar laws. SCE&G maintains an environmental assessment program to identify and evaluate current and former operations sites that could require clean-up. In addition, regulators from the EPA and other federal or state agencies periodically notify SCE&G that it may be required to perform or participate in the investigation and remediation of a hazardous waste site. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. These estimates are refined as additional information becomes available; therefore, actual expenditures may differ significantly from the original estimates. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Such amounts are recorded in regulatory assets and amortized, with recovery provided through rates.

SCE&G is responsible for four decommissioned MGP sites in South Carolina which contain residues of by-product 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 at least through 2017 and will cost an additional $19.1 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, 2015, deferred amounts, net of amounts previously recovered through rates and insurance settlements, totaled $35.0 million and are included in regulatory assets.

10. AFFILIATED TRANSACTIONS

CGT transports natural gas to SCE&G to serve retail gas customers and certain electric generation requirements. Prior to January 31, 2015, CGT was a wholly-owned subsidiary of SCANA, and SCE&G's transactions with CGT prior to January 31, 2015 were affiliated transactions. SCE&G's affiliated purchases from CGT totaled approximately $8.8 million for the three months ended June 30, 2014, and $3.4 million and $14.7 million for the six months ended June 30, 2015 and 2014, respectively. SCE&G's affiliated payables to CGT for transportation services were $3.3 million at December 31, 2014, and SCE&G's affiliated receivables from CGT related to such transportation services were $1.2 million at December 31, 2014.

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 $32.8 million and $53.9 million for the three months ended June 30, 2015 and 2014, respectively, and $67.3 million and $107.3 million for the six months ended June 30, 2015 and 2014, respectively. SCE&G’s payables to SEMI for such purposes were $10.2 million at June 30, 2015 and $12.6 million at December 31, 2014.

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 accounts for this investment using the equity method. SCE&G’s total purchases from this affiliate were $49.6 million and $70.2 million for the three months ended June 30, 2015 and 2014, respectively, and $119.7 million and $109.5 million for the six months ended June 30, 2015 and 2014, respectively. SCE&G’s total sales to this affiliate were $49.4 million and $69.9 million for the three months ended June 30, 2015 and 2014, respectively, and $119.1 million and $108.9 million for the six months ended June 30, 2015 and 2014, respectively. SCE&G’s receivable from this affiliate was $23.6 million at June 30, 2015 and $27.8 million at December 31, 2014. SCE&G’s payable to this affiliate was $23.7 million at June 30, 2015 and $27.9 million at December 31, 2014.

SCANA Services provides the following services to Consolidated SCE&G, which are rendered at direct or allocated cost: information systems services, telecommunications 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. In addition, SCANA Services processes and pays invoices for Consolidated SCE&G and is reimbursed. Costs for these services were $72.1 million and $70.2 million for the three months ended June 30, 2015 and 2014, respectively, and $145.2 million and $146.4 million for the six months ended June 30, 2015 and 2014, respectively. Consolidated SCE&G's payables to SCANA Services for these services were $46.0 million at June 30, 2015 and $47.3 million at December 31, 2014.

Money pool borrowings from an affiliate are described in Note 4.

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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, 2015			
Electric Operations	$639	$216	n/a
Gas Distribution	70	2	n/a
Adjustments/Eliminations	—	—	$107
Consolidated Total	$709	$218	$107
Six Months Ended June 30, 2015			
Electric Operations	$1,269	$415	n/a
Gas Distribution	212	40	n/a
Adjustments/Eliminations	—	—	$230
Consolidated Total	$1,481	$455	$230
Three Months Ended June 30, 2014			
Electric Operations	$612	$143	n/a
Gas Distribution	86	2	n/a
Adjustments/Eliminations	—	—	$96
Consolidated Total	$698	$145	$96
Six Months Ended June 30, 2014			
Electric Operations	$1,292	$341	n/a
Gas Distribution	265	42	n/a
Adjustments/Eliminations	—	—	$219
Consolidated Total	$1,557	$383	$219

Segment Assets	June 30, 2015	December 31, 2014
Electric Operations	$10,454	$10,182
Gas Distribution	741	721
Adjustments/Eliminations	2,961	3,204
Consolidated Total	$14,156	$14,107

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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, 2014.

RESULTS OF OPERATIONS
FOR THE THREE AND SIX MONTHS ENDED JUNE 30, 2015
AS COMPARED TO THE CORRESPONDING PERIODS IN 2014

Net Income

Net income for Consolidated SCE&G was as follows:

	Second Quarter			Year to Date		
Millions of dollars	2015	Change	2014	2015	Change	2014
Net income	$110.9	11.5 %	$99.5	$237.2	5.1 %	$225.7

Second Quarter and Year to Date

Net income increased primarily due to higher electric operations margins partially offset by lower gas distribution margins, lower other income, higher operation and maintenance expense, higher property taxes, higher depreciation expense, higher interest cost, and higher income taxes, 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 2015:

Declaration Date	Amount	Quarter Ended	Payment Date
February 20, 2015	$70.7 million	March 31, 2015	April 1, 2015
April 30, 2015	$69.7 million	June 30, 2015	July 1, 2015
July 30, 2015	$70.5 million	September 30, 2015	October 1, 2015

Electric Operations

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

	Second Quarter			Year to Date		
Millions of dollars	2015	Change	2014	2015	Change	2014
Operating revenues	$638.9	4.3 %	$612.4	$1,269.2	(1.8)%	$1,292.3
Less: Fuel used in generation	163.5	(23.1)%	212.7	338.1	(20.7)%	426.5
Purchased power	11.5	(29.4)%	16.3	24.3	(41.2)%	41.3
Margin	463.9	21.0 %	383.4	906.8	10.0 %	824.5
Other operation and maintenance expenses	124.8	3.0 %	121.2	247.2	0.4 %	246.1
Depreciation and amortization	73.9	2.5 %	72.1	147.2	2.3 %	143.9
Other taxes	48.3	5.5 %	45.8	96.8	3.8 %	93.3
Operating Income	$216.9	50.3 %	$144.3	$415.6	21.8 %	$341.2

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Second Quarter

Margin increased due to downward adjustments of $60.1 million in 2014, compared to downward adjustments of $0.7 million in 2015, pursuant to orders of the SCPSC, related to fuel cost recovery and SCE&G’s DSM Programs. These adjustments were fully offset by the recognition, within other income, of gains realized upon the late 2013 settlement of certain derivative interest rate contracts and the application, as a reduction to operation and maintenance expenses, of a portion of SCE&G’s storm damage reserve, both of which had been deferred in regulatory accounts. Margin also increased due to base rate increases under the BLRA of $15.5 million and residential and commercial customer growth of $5.1 million. These increases were partially offset by lower industrial margins of $2.5 million. Operations and maintenance expenses increased due to the application of $5.0 million in 2014 of SCE&G’s storm damage reserve to offset downward revenue adjustments related to its DSM Programs and due to the amortization of $1.1 million of DSM Programs cost. These increases were partially offset by a decrease in labor of $1.1 million, primarily due to lower incentive compensation. Depreciation and amortization and other taxes increased due to net plant additions.

Year to Date

Margin increased due to downward adjustments of $60.1 million in 2014, compared to downward adjustments of $5.2 million in 2015, pursuant to orders of the SCPSC, related to fuel cost recovery and SCE&G’s DSM Programs. These adjustments were fully offset as described under Second Quarter. Margin also increased due to base rate increases under the BLRA of $31.5 million and residential and commercial customer growth of $9.2 million. These increases were partially offset by the effects of weather of $10.2 million, lower industrial margins of $6.6 million and lower collections under SCE&G’s rate rider for pension costs of $3.0 million. Operations and maintenance expenses increased due to the application of $5.0 million in 2014 of SCE&G’s storm damage reserve to offset downward revenue adjustments related to its DSM Programs and due to the amortization of $1.4 million of DSM Programs cost. These increases were partially offset by a decrease in labor of $4.8 million, primarily due to lower incentive compensation and lower pension costs as a result of lower rate rider collections, and lower storm expenses of $1.8 million. Depreciation and amortization and other taxes increased due to net plant additions.

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

	Second Quarter				Year to Date			
Classification	2015	Change		2014	2015	Change		2014
Residential	1,907	0.2	%	1,904	3,999	(1.4	)%	4,055
Commercial	1,899	4.1	%	1,825	3,611	1.0	%	3,575
Industrial	1,599	3.7	%	1,542	3,066	2.4	%	2,994
Other	152	2.0	%	149	293	1.0	%	290
Total Retail Sales	5,557	2.5	%	5,420	10,969	0.5	%	10,914
Wholesale	237	0.9	%	235	483	0.8	%	479
Total Sales	5,794	2.5	%	5,655	11,452	0.5	%	11,393

Second Quarter and Year to Date

Retail sales volume increased primarily due to customer growth. Year to date volumes were partially offset by the effects of weather in the first quarter.

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Gas Distribution

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

	Second Quarter			Year to Date		
Millions of dollars	2015	Change	2014	2015	Change	2014
Operating revenues	$69.8	(18.8)%	$86.0	$212.1	(19.9)%	264.9
Less: Gas purchased for resale	39.6	(28.6)%	55.5	114.1	(30.7)%	164.7
Margin	$30.2	(1.0)%	$30.5	$98.0	(2.2)%	$100.2
Other operation and maintenance expenses	16.3	(1.8)%	16.6	32.6	(2.4)%	33.4
Depreciation and amortization	6.7	4.7%	6.4	13.3	4.7%	12.7
Other taxes	6.2	6.9%	5.8	12.4	6.0%	11.7
Operating Income	$1.0	(41.2)%	$1.7	$39.7	(6.4)%	$42.4

Second Quarter and Year to Date

Margin decreased primarily due to a SCPSC-approved decrease in base rates under the RSA which became effective in November 2014. Operation and maintenance expenses decreased due to nonlabor operating expenses. Depreciation and amortization and other taxes increased due to net plant additions.

Sales volumes (in MMBTU) related to gas distribution margin by class, including transportation, were as follows:

	Second Quarter			Year to Date		
Classification (in thousands)	2015	Change	2014	2015	Change	2014
Residential	934	(18.1)%	1,140	8,626	(9.9)%	9,579
Commercial	2,568	(1.2)%	2,599	7,211	(7.3)%	7,783
Industrial	4,694	—%	4,694	8,868	(3.8)%	9,214
Transportation	1,280	5.8%	1,210	2,348	26.0%	1,864
Total	9,476	(1.7)%	9,643	27,053	(4.9)%	28,440

Second Quarter and Year to Date

Residential and commercial firm sales volumes decreased due to the effects of weather and due to lower average use. These decreases were partially offset by customer growth. Commercial and industrial interruptible volumes decreased due to customer usage, and for year to date such volumes also decreased due to curtailments in the first quarter. Transportation volumes increased due to customers shifting to transportation only service.

Other Operating Expenses

Other operating expenses were as follows:

	Second Quarter			Year to Date		
Millions of dollars	2015	Change	2014	2015	Change	2014
Other operation and maintenance	$141.1	2.4%	$137.8	$279.8	0.1%	$279.5
Depreciation and amortization	80.6	2.7%	78.5	160.5	2.5%	156.6
Other taxes	54.5	5.6%	51.6	109.2	4.0%	105.0

Second Quarter

Operations and maintenance expense increased due to the application, in 2014, of $5.0 million of SCE&G’s storm damage reserve to offset downward revenue adjustments related to its DSM Programs and due to the amortization of $1.1 million of DSM Programs cost. These increases were partially offset by a decrease in labor costs of $1.1 million, primarily due to lower incentive compensation. Depreciation and amortization increased due to net plant additions. Other taxes increased due primarily to higher property taxes associated with plant additions.

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Year to Date

Operations and maintenance expense increased due to the application, in 2014, of $5.0 million of SCE&G's storm damage reserve to offset downward revenue adjustments related to its DSM Programs and due to the amortization of $1.4 million of DSM Programs cost. These increases were offset by a decrease in labor costs of $4.8 million, primarily due to lower incentive compensation and lower pension costs as a result of lower rate rider collections, and lower storm expenses of $1.8 million. Depreciation and amortization increased due to net plant additions. Other taxes increased due primarily to higher property taxes associated with plant additions.

Other Income (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. Other income and expense and AFC were as follows:

	Second Quarter			Year to Date		
Millions of dollars	2015	Change	2014	2015	Change	2014
Other Income	$9.0	(84.9)%	$59.5	$17.8	(71.3)%	$62.1
Other Expense	6.8	(6.8)%	7.3	14.2	10.9%	12.8
Allowance for Funds Used During Construction	6.1	(15.3)%	7.2	11.0	(13.4)%	12.7

Second Quarter

Other income decreased due primarily to the recognition of $55.1 million of gains in 2014, compared to $0.7 million in 2015, realized upon the settlement of certain interest rate derivative contracts previously recorded as regulatory liabilities pursuant to the SCPSC orders previously discussed. Such gain recognition was fully offset by downward adjustments to revenues reflected within electric margin and had no effect on net income (see electric margin discussion). AFC decreased due to lower AFC rates.

Year to Date

Other income decreased due primarily to the recognition of $55.1 million of gains in 2014, compared to $5.2 million in 2015, realized upon the settlement of certain interest rate derivative contracts previously recorded as regulatory liabilities pursuant to the SCPSC orders previously discussed. Such gain recognition was fully offset by downward adjustments to revenues reflected within electric margin and had no effect on net income (see electric margin discussion). AFC decreased due to lower AFC rates.

Interest Expense

Interest charges increased primarily due to increased borrowings.

Income Taxes

Income taxes for the three and six months ended June 30, 2015 were higher than the same periods in 2014 primarily due to higher income before taxes.

LIQUIDITY AND CAPITAL RESOURCES

Consolidated SCE&G anticipates that its cash obligations will be met through internally generated funds, additional short- and long-term borrowings, 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, 2015 was 3.74 and 3.74, respectively.

SCE&G received approximately $196 million, net, in equity from its parent company during the six months ended June 30, 2015.

In May 2015, SCE&G issued $500 million of 5.1% first mortgage bonds due June 1, 2065. Proceeds from this sale were used 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.

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 TD Bank N.A. These letters of credit expire, subject to renewal, in the fourth quarter of 2019.

At June 30, 2015, Consolidated SCE&G had net available liquidity of approximately $1.2 billion, comprised of cash on hand and available amounts under lines of credit. The credit agreements total an aggregate of $1.4 billion, of which $200 million is scheduled to expire in October 2016 and the remainder is scheduled to expire in October 2019. 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 24 years at a weighted average effective interest rate of 5.8%. 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, banks, 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 $200 million outstanding with maturity dates of one year or less. The authority described herein will expire in October 2016.

SCE&G's current preliminary estimates of its capital expenditures for new nuclear construction (including transmission) for 2015 through 2017, which are subject to continuing review and adjustment, are $927 million in 2015, $979 million in 2016, and $899 million in 2017.

For additional information, see Note 4 to the consolidated financial statements.

OTHER MATTERS

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

ITEM 4. CONTROLS AND PROCEDURES

As of June 30, 2015, 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, 2015, 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, 2015, that has materially affected or is reasonably likely to materially affect SCE&G's internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

SCANA:

The following table provides information about purchases by or on behalf of SCANA or any affiliated purchaser (as defined in Rule 10b-18(a)(3) under the Securities Exchange Act of 1934, as amended (Exchange Act)) of shares or other units of any class of SCANA's equity securities that are registered pursuant to Section 12 of the Exchange Act:

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Issuer Purchases of Equity Securities

Period	(a) Total number of shares (or units) purchased	(b) Average price paid per share (or unit)	(c) Total number of shares (or units) purchased as part of publicly announced plans or programs	(d) Maximum number (or approximate dollar value) of shares (or units) that may yet be purchased under the plans or programs
April 1-30	276,405	$54.91	276,405	
May 1-31	78,912	$52.60	78,912	
June 1-30	78,888	$51.20	78,888	
Total	434,205		434,205	*

*On December 16, 2014 SCANA announced a program to convert from original issue to open market purchase of SCANA common stock for all applicable compensation and dividend reinvestment plans once the sales of certain subsidiaries were completed. The sales of the subsidiaries were completed in the first quarter of 2015. This program has no stated maximum number of shares that may be purchased and no stated expiration date.

ITEM 5. OTHER INFORMATION

SCANA and SCE&G:

SCANA and SCE&G post information from time to time regarding developments relating to SCE&G's new nuclear project and other matters of interest to investors on SCANA's website at www.scana.com (which is not intended to be an active hyperlink; the information on SCANA's website is not a part of this report or any other report or document that SCANA or SCE&G files with or furnishes to the SEC). On SCANA's homepage, there is a yellow box containing links to the Nuclear Development and Other Investor Information sections of the website. The Nuclear Development section contains a yellow box with a link to project news and updates. The Other Investor Information section of the website contains a link to recent investor related information that cannot be found at other areas of the website. Some of the information that will be posted from time to time, including the quarterly reports that SCE&G submits to the SCPSC and the ORS in connection with the new nuclear project, may be deemed to be material information that has not otherwise become public. Investors, media and other interested persons are encouraged to review this information and can sign up, under the Investor Relations Section of the website, for an email alert when there is a new posting in the Nuclear Development and Other Investor Information yellow box.

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 7, 2015		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)
10.01	X		Form of Indemnification Agreement (Filed as Exhibit 10.01 to Form 10-Q for the period ended June 30, 2012 and incorporated by reference herein)
10.02	X		General Release and Severance Agreement between SCANA and George J. Bullwinkel, Jr. (Filed as Exhibit 10.02 to Form 10-Q for the quarter ended March 31, 2015 and incorporated by reference herein)
10.03	X		Independent Contractor Agreement between SCANA Services, Inc. and George J. Bullwinkel, Jr. (Filed as Exhibit 10.03 to Form 10-Q for the quarter ended March 31, 2015 and incorporated by reference herein)
10.04	X		SCANA Long-Term Equity Compensation Plan effective February 19, 2015 (Filed as Exhibit 4.05 to Registration Statement No. 333-204218 and incorporated as reference herein)
12.01	X	X	Statement Re Computation of Ratios (Filed herewith)
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 and Principal Financial Officer Pursuant to 18 U.S.C. Section 1350 (Furnished herewith)
32.02		X	Certification of Principal Executive Officer and 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.