NOTES TO THE FINANCIAL STATEMENTS: ELECTRIC

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The Electric Utility (Utility) exists under, and by virtue of, the City of Riverside (City) Charter enacted in 1883. The Utility is responsible for the generation, transmission and distribution of electric power for sale in the City. The accompanying financial statements present only the financial position and the results of operations of the Utility, which is an enterprise fund of the City, and are not intended to present fairly the financial position and results of operations of the City in conformity with generally accepted accounting principles. However, certain disclosures are for the City as a whole, since such information is generally not available for the Utility on a separate fund basis. All amounts, unless otherwise indicated, are expressed in thousands of dollars.

BASIS OF ACCOUNTING

The Utility uses the accrual basis of accounting as required for enterprise funds with accounting principles generally accepted in the United States of America as applicable to governments. Effective July 1, 2012, the Utility adopted Governmental Accounting Standards Board (GASB) Statement No. 62, *Codification of Accounting and Financial Reporting Guidance Contained in Pre-November 30, 1989 FASB and AICPA Pronouncements* (GASB 62), which incorporates into the GASB's authoritative literature certain accounting and financial reporting guidance from all sources of generally accepted accounting principles for state and local governments issued on or before November 30, 1989 so that they derive from a single source. The accounting records of the Utility are also substantially in conformity with the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission (FERC). The Utility is not subject to the regulations of the FERC.

USE OF ESTIMATES

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

REVENUE RECOGNITION

The Utility customers are billed monthly. Unbilled electric service charges, including Public Benefit Programs, are recorded at year-end and are included in accounts receivable. Unbilled accounts receivable, totaled $15,324 at June 30, 2013, and $13,496 at June 30, 2012.

An allowance for doubtful accounts is maintained for the Utility and miscellaneous accounts receivable. The balance in this account is adjusted at fiscal year-end to approximate the amount anticipated to be uncollectible.

UTILITY PLANT AND DEPRECIATION

The Utility defines capital assets as assets with an initial, individual cost of more than five thousand dollars and an estimated useful life in excess of one year. Utility plant assets are valued at historical cost or estimated historical cost, if actual historical cost is not available. Costs include labor; materials; interest during construction; allocated indirect charges such as engineering, supervision, construction and transportation equipment; retirement plan contributions and other fringe benefits. Contributed plant assets are valued at estimated fair value on the date contributed. The cost of relatively minor replacements is included in maintenance expense. Intangible assets that cost more than one hundred thousand dollars with useful lives of at least three years are capitalized and are recorded at cost.

Depreciation is provided over the estimated useful lives of the related assets using the straight-line method. The estimated useful lives are as follows:

Production plant	10-40 years
Transmission and distribution plant	20-50 years
General plant and equipment	5-50 years
Intangibles	3-5 years

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

NUCLEAR FUEL

The Utility amortizes and charges to expense, the cost of nuclear fuel, on the basis of actual thermal energy produced relative to total thermal energy expected to be produced over the life of the fuel. In accordance with the Nuclear Waste Disposal Act of 1982, the Utility is charged one dollar per megawatt-hour (MWh) of energy generated by the Utility's share of San Onofre Nuclear Generating Station's (SONGS) Units 2 and 3 to provide for estimated future storage and disposal of spent nuclear fuel. The Utility pays this fee to its operating agent, Southern California Edison (SCE), on a quarterly basis. Due to the closure of SONGS Units 2 and 3, nuclear fuel inventory was considered impaired and written off as an extraordinary item on the Statement of Revenues, Expenses and Changes in Net Position at June 30, 2013 (see Notes 7 and 10).

RESTRICTED ASSETS

Proceeds of revenue bonds yet to be used for capital projects, as well as certain resources set aside for debt service, are classified as restricted assets in the Statements of Net Position because their use is limited by applicable bond covenants. Funds set aside for the nuclear decommissioning and regulatory requirements relating to greenhouse gas allowances are also classified as restricted assets because their use is legally restricted to a specific purpose.

In January 1998, the Utility began collecting a surcharge for Public Benefit Programs on customer utility bills. This surcharge is mandated by state legislation included in Assembly Bill 1890 and is restricted to various socially beneficial programs and services. The programs and services include cost effective demand-side management services to promote energy efficiency and conservation and related education and information; ongoing support and new investments in renewable resource technologies; energy research and development; and programs and services for low-income electric customers. The activity associated with the surcharge for Public Benefit Programs is reflected in the accompanying financial statements on the Statements of Net Position, Statements of Revenues, Expenses and Changes in Net Position, and Statements of Cash Flows.

CASH AND INVESTMENTS

In accordance with the Utility policy, the Utility's cash and investments, except for cash and investments with fiscal agents, are invested in a pool managed by the Treasurer of the City. The Utility does not own specific, identifiable investments of the pool. The pooled interest earned is allocated monthly based on the month end cash balances.

The Utility values its cash and investments in accordance with the provisions of the GASB Statement No. 31, *Accounting and Financial Reporting for Certain Investments and External Investment Pools* (GASB 31), which requires governmental entities, including governmental external investment pools, to report certain investments at fair value in the Statements of Net Position and recognize the corresponding change in the fair value of investments in the year in which the change occurred. Fair value is determined using quoted market prices.

Cash accounts of all funds are pooled for investment purposes to enhance safety and liquidity, while maximizing interest earnings.

City-wide information concerning cash and investments for the year ended June 30, 2013, including authorized investments, custodial credit risk, credit and interest rate risk for debt securities and concentration of investments, carrying amount and market value of deposits and investments may be found in the notes to the City's "Comprehensive Annual Financial Report."

CASH AND INVESTMENTS AT FISCAL AGENTS

Cash and investments maintained by fiscal agents are considered restricted by the Utility and are used to fund construction of capital assets. A portion is pledged as collateral for payment of principal and interest on outstanding bonds and certain funds are set aside to decommission the Utility's proportionate share of Units 2 and 3 at SONGS.

INTERNALLY RESTRICTED CASH RESERVES

The Utility has several cash reserves established for strategic purposes, all of which are considered internally restricted assets. The balance as of June 30, 2013 and 2012 respectively are as follows: Regulatory Risk Reserve $15,000 and $15,000, Energy Risk Management Reserve $30,000 and $30,000, Operating Reserve $116,031 and $108,031, and Decommissioning Reserve $132 and $0, for a combined total of $161,163 and $153,031 and are included as a component of unrestricted cash and cash equivalents in the accompanying Statements of Net Position.

ADVANCES

Advances have been recorded as a result of agreements between the Utility and the City. The balance as of June 30, 2013 and 2012 are $7,507 and $7,835, respectively.

DERIVATIVES

The Utility accounts for derivative instruments using GASB Statement No. 53, *Accounting and Financial Reporting for Derivative Instruments* (GASB 53). This Statement requires the Utility to report its derivative instruments at fair value. Changes in fair value for effective hedges are to be reported as deferred inflow and outflow of resources on the Statements of Net Position. Changes in fair value of derivative instruments not meeting the criteria for an effective hedge, or that are associated with investments are to be reported in the investment section of the Statements of Revenues, Expenses and Changes in Net Position.

The Utility has determined that its interest rate swaps associated with variable rate obligations are derivative instruments under GASB 53. See Note 4 Long-Term Obligations for further discussion related to the Utility's interest rate swaps.

Various transactions permitted in the Utility's power resources risk management policies may be considered derivatives, including energy and/or gas transactions for swaps, options, forward arrangements and congestion revenue rights (CRR). GASB 53 allows an exception for the Statements of Net Position deferral hedges that meet the normal purchases and normal sales exception. The Utility has determined that all of its contracts including CRRs fall under the scope of normal purchases/sales and are exempt from GASB 53.

BOND PREMIUMS AND GAINS/LOSSES ON REFUNDING

Bond premiums and gains/losses on refunding (including gains/losses related to interest rate swap transactions) are deferred and amortized over the term of the new bonds using the effective interest method. Bonds payable are reported net of the applicable bond premiums. Gains/losses on refunding are reported as deferred inflows or outflows of resources.

NUCLEAR DECOMMISSIONING LIABILITY

Federal regulations require the Utility to provide for the future decommissioning of its ownership share of the nuclear units at SONGS. The Utility has established trust accounts to accumulate resources for the decommissioning of the nuclear power plant and restoration of the beachfront at SONGS. Based on the most recent site specific cost estimate as of July 2013, prepared by ABZ Incorporated, the Utility has fully funded the SONGS nuclear decommissioning liability. With the recent retirement of SONGS units 2 and 3, there is much uncertainty as to future unknown costs to decommission SONGS. Although management believes the current cost estimate is the upper bound of decommissioning obligations, the Utility has conservatively decided to continue to set aside $1,600 per year in an internally restricted cash reserve for unexpected costs not contemplated in the current estimates.

Increases to the funds held for decommissioning liability are from amounts set aside and investment earnings. The investment earnings are included in investment income in the Utility's financial statements. These earnings, as well as amounts set aside, are reflected as decommissioning expense which is considered part of power supply costs. To date, the Utility has set aside $76,035 in cash investments with the trustee and $132 in an internally restricted decommissioning reserve as the Utility's estimated share of the decommissioning cost of SONGS, and these amounts are reflected as restricted assets and unrestricted cash and cash equivalents, respectively, on the Statements of Net Position. The Utility's decommissioning liability is equivalent to the total funds accumulated and is reflected as an other non-current liability. The plant site easement at SONGS terminates May 2024. The plant must be decommissioned and the site restored by the time the easement terminates.

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

CAPITAL LEASES

The Utility has entered into eight capital lease agreements as a lessee for financing eight compressed natural gas heavy duty service trucks. In fiscal year ended June 30, 2013, the Utility entered into six additional capital lease agreements for financing service trucks. All leases have seven year terms with monthly payments with interest rates ranging from 2.50% to 5.87%. The total gross value of all leases is $4,403 with depreciation over the seven year terms of the leases using the straight-line method.

As of June 30, 2013 and 2012, the total liability was $2,550 and $1,303, respectively, with the current portion included in accounts payable and other accruals. The remaining annual lease payments for the life of the leases are $700 in fiscal year ended June 30, 2014, $687 in fiscal year ended June 30, 2015, $324 in the fiscal year ended June 30, 2016, $259 annually through fiscal year ended June 30, 2019, and $246 in the fiscal year ended June 30, 2020. Total outstanding lease payments are $2,734, with $2,550 representing the present value of the net minimum lease payments and $184 representing interest.

CUSTOMER DEPOSITS

The City holds customer deposits as security for the payment of utility bills and design fee deposits for future construction of electrical facilities. The Utility's portion of these deposits as of June 30, 2013 and 2012 was $3,371 and $3,148, respectively.

COMPENSATED ABSENCES

The accompanying financial statements include accruals for salaries, fringe benefits and compensated absences due to employees at June 30, 2013 and 2012. The Utility treats compensated absences due to employees as an expense and a liability of which a current portion is included in accounts payable and other accruals in the accompanying Statements of Net Position. The amount accrued for compensated absences was $4,359 at June 30, 2013 and $4,294 at June 30, 2012.

Employees receive 10 to 25 vacation days per year based upon length of service. A maximum of two years vacation accrual may be accumulated and unused vacation is paid in cash upon separation.

Employees primarily receive one day of sick leave for each month of employment with unlimited accumulation. Upon retirement or death, certain employees or their estates receive a percentage of unused sick-leave paid in a lump sum based on longevity.

INSURANCE PROGRAMS

The Utility participates in a self-insurance program for workers' compensation and general liability coverage that is administered by the City. The Utility pays an amount to the City based on actuarial estimates of the amounts needed to fund prior and current year claims and incidents that have been incurred but not reported. The City maintains property insurance on most City property holdings, including the Utility Plant with a limit of $1 billion.

City-wide information concerning risks, insurance policy limits and deductibles and designation of general fund balance for risk for the year ended June 30, 2013, may be found in the notes to the City's "Comprehensive Annual Financial Report."

Although the ultimate amount of losses incurred through June 30, 2013 is dependent upon future developments, management believes that amounts paid to the City are sufficient to cover such losses. Premiums paid to the City by the Utility including the Public Benefit Programs, were $818 and $737 for the years ended June 30, 2013 and 2012, respectively. Any losses above the City's reserves would be covered through increased rates charged to the Utility in future years.

EMPLOYEE RETIREMENT PLAN

The City contributes to the California Public Employees Retirement System (PERS), an agent multiple employer public employee defined benefit pension plan. PERS provides retirement and disability benefits, annual cost-of-living adjustments, and death benefits to plan members and beneficiaries. PERS acts as a common investment and administrative agent for participating public entities within the State of California. Benefit provisions and all other requirements are established by state statute and City ordinance.

All permanent full-time and selected part-time employees are eligible for participation in PERS. Benefits vest after five years of service and are determined by a formula that considers the employee's age, years of service and salary. The City has the following multiple tier retirement plan with benefits varying by plan for non-safety employees:

> 1st Tier – The retirement formula is 2.7% at age 55. The Utility pays the employee share (8%) of contributions on their behalf and for their account.
>
> 2nd Tier – The retirement formula is 2.7% at age 55. Employees hired on or after October 19, 2011 pay their share (8%) of contributions.
>
> 3rd Tier – The retirement formula is 2% at age 62 for new members hired on or after January 1, 2013. Employees must pay the employee share ranging from 7-8% based on bargaining group classification. Classic members (PERS members prior to 12/31/12) hired on or after January 1, 2013 may be placed in a different tier.

The Utility is required to contribute the remaining amounts necessary to fund the benefits for its employees using the actuarial basis recommended by the PERS actuaries and actuarial consultants and adopted by the PERS Board of Administration. The Utility's total contribution to PERS, including the Public Benefit Programs, as of June 30, 2013 and 2012 was $8,633 and $8,754 respectively. The employer portion of the PERS funding as of June 30, 2013 and 2012 was 18.28 percent and 18.44 percent, respectively, of annual covered payroll.

City-wide information concerning elements of the unfunded actuarial accrued liabilities, contributions to PERS for the year ended June 30, 2013 and recent trend information may be found in the notes to the City's "Comprehensive Annual Financial Report."

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

PENSION OBLIGATION BONDS AND NET PENSION ASSET

The Utility is obligated to pay its share of the City's pension obligation bonds, which the City issued in 2005. The Utility's proportional share of the outstanding principal amount of the bonds was $11,781 and $12,003 as of June 30, 2013 and 2012, respectively, and is shown on the Statements of Net Position as an Advance from City – pension obligation. The bond proceeds were deposited with PERS to fund the unfunded actuarial accrued liability for non-safety employees. The net pension asset will be amortized over 19 years in accordance with the method used by PERS for calculating actuarial gains and losses. The balance in the net pension asset as of June 30, 2013 and 2012 was $11,954 and $12,380, respectively. For more discussion relating to the City's issue, see the notes to the City's "Comprehensive Annual Financial Report" for the fiscal year ended June 30, 2013.

OTHER POSTEMPLOYMENT BENEFITS

The City provides healthcare benefits to retirees in the form of an implied rate subsidy. Retirees and active employees are insured together as a group, thus creating a lower rate for retirees than if they were insured separately. Although the retirees are solely responsible for the cost of their health insurance benefits through this plan, the retirees receive the benefit of a lower rate. The difference between these amounts is the implied rate subsidy, which is considered an other postemployment benefit (OPEB) under GASB Statement No. 45, *Accounting and Financial Reporting by Employers for Postemployment Benefits Other Than Pensions* (GASB 45).

Retiree coverage terminates either when the retiree becomes covered under another employer health plan, or when the retiree reaches Medicare eligibility age, which is currently age 65. Spousal coverage is available until the retiree becomes covered under another employer health plan, attains Medicare eligibility age, or dies. However, the retiree benefit continues to the surviving spouse if the retiree elects the PERS survivor annuity.

The contribution requirements are established by the City Council. The City is not required by law or contractual agreement to provide funding other than the pay-as-you-go amount necessary to provide current benefits to eligible retirees and beneficiaries.

The Utility's annual OPEB cost (expense) is reported based on the annual required contribution (ARC) of the employer, an amount actuarially determined in accordance with GASB 45. The ARC represents a level of funding that, if paid on an ongoing basis, is projected to cover normal cost each year and amortize any unfunded actuarial liability (or funding excess) (UAAL) over a period not to exceed thirty years. The Utility's OPEB liability including Public Benefit Programs as of June 30, 2013 and 2012 was $4,928 and $3,869, respectively.

City-wide information concerning the description of the plan, funding policy and annual OPEB cost, funding status and funding progress, and actuarial methods and assumptions for the year ended June 30, 2013 can be found in the notes to the City's "Comprehensive Annual Financial Report."

DEFERRED OUTFLOWS AND DEFERRED INFLOWS OF RESOURCES

When applicable, the Statements of Net Position will report a separate section for deferred outflows of resources. Deferred outflows of resources represent outflows of resources (consumption of net position) that apply to future periods and that, therefore, will not be recognized as an expense or expenditure until that time.

When applicable, the Statements of Net Position will report a separate section for deferred inflows of resources. Deferred inflows of resources represent inflows of resources (acquisition of net position) that apply to future periods and that, therefore, are not recognized as an inflow of resources (revenue) until that time.

REGULATORY ASSETS

In accordance with GASB 62, enterprise funds that are used to account for rate-regulated activities are permitted to defer certain expenses and revenues that would otherwise be recognized when incurred, provided that the City is recovering or expects to recover or refund such amounts in rates charged to its customers. Accordingly, regulatory assets relating to debt issuance costs and replacement power costs have been recorded by the Utility.

NET POSITION

The Utility's net position represents the difference between assets and deferred outflows of resources less liabilities and deferred inflows of resources, which is classified into the following three components:

Net investment in capital assets – this component consists of capital assets (net of accumulated depreciation) and unamortized debt expenses reduced by the outstanding balances of any bonds or other borrowings that are attributable to the acquisition, construction, or improvement of those assets, excluding unspent bond proceeds.

Restricted – this component consists of net position on which constraints are placed as to their use. Constraints include those imposed by creditors (such as through debt covenants), contributors, or laws or regulation of other governments or constraints imposed by law through constitutional provisions or through enabling legislation.

Unrestricted – this component consists of net position that does not meet the definition of "restricted" or "net investment in capital assets."

CONTRIBUTIONS TO THE CITY'S GENERAL FUND

Pursuant to the City of Riverside Charter, the Utility may transfer up to 11.5 percent of its prior year's gross operating revenues including adjustments to the City's general fund. In fiscal years ended June 30, 2013 and 2012, $37,186 and $33,533, respectively was transferred representing 11.5 percent.

CASH AND CASH EQUIVALENTS

For the Statements of Cash Flows, cash and cash equivalents include all unrestricted and restricted highly liquid investments with original purchase maturities of three months or less, and all bond construction proceeds available for capital projects. Pooled cash and investments in the City's treasury represent monies in a cash management pool. Such accounts are similar in nature to demand deposits, and are classified as cash equivalents for the purpose of presentation in the Statements of Cash Flows.

BUDGET AND BUDGETARY ACCOUNTING

The Utility presents, and the City Council adopts, an annual budget. The proposed budget includes estimated expenses and forecasted revenues. The City Council adopts the Utility's budget in June each year via resolution.

RECLASSIFICATIONS

Certain reclassifications have been made to prior year's financial statements to conform with the current year's presentation.

PRIOR YEAR DATA

Selected information regarding the prior year has been included in the accompanying financial statements. This information has been included for comparison purposes only and does not represent a complete presentation in accordance with generally accepted accounting principles. Accordingly, such information should be read in conjunction with the Utility's prior year financial statements, from which this selected financial data was derived.


RERC
RIVERSIDE #1
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NOx WATER RETURN

NOTE 2. CASH AND INVESTMENTS

Cash and investments at June 30, 2013 and 2012, consist of the following (in thousands):

	June 30, 2013	June 30, 2012
	Fair Value	
Equity interest in City Treasurer's investment pool	$ 223,414	$ 211,570
Cash and investments at fiscal agent	211,072	238,254
Total cash and investments	$ 434,486	$ 449,824

The amounts above are reflected in the accompanying financial statements as:

	June 30, 2013	June 30, 2012
Unrestricted cash and cash equivalents	$ 197,823	$ 187,541
Restricted cash and cash equivalents	25,591	24,029
Restricted cash and investments at fiscal agent	211,072	238,254
Total cash and investments	$ 434,486	$ 449,824

Cash and investments distribution by maturities as of year end are as follows:

		Remaining Maturity (In Months)			
Investment Type	**Total**	**12 Months or less**	**13 to 24 Months**	**25 to 60 Months**	**More than 60 Months**
Held by fiscal agent					
Money market funds	$ 3,142	$ 3,142	$ -	$ -	$ -
Federal agency securities	53,344	-	-	53,344	-
Investment contracts [1]	134,003	119,211	4,031	-	10,761
Corp medium term notes	20,583	-	-	20,583	-
City Treasurer's investment pool [2]					
Money market funds	31,975	31,975	-	-	-
Federal agency securities	101,606	17,490	9,648	74,468	-
Corp medium term notes	31,718	5,448	9,442	16,828	-
State investment pool	52,048	52,048	-	-	-
Negotiable Certificate of Deposit	6,067	2,701	1,953	1,413	-
Total	$ 434,486	$ 232,015	$ 25,074	$ 166,636	$ 10,761

Presented below is the actual rating as of year end for each investment type:

		Rating as of Year End					
Investment Type	**Total**	**AAA**	**AA+**	**AA**	**A+**	**A**	**Unrated**
Held by fiscal agent							
Money market funds	$ 3,142	$ 3,104	$ -	$ -	$ -	$ -	$ 38
Federal agency securities	53,344	53,344	-	-	-	-	-
Investment contracts [1]	134,003	-	-	-	-	-	134,003
Corp medium term notes	20,583	-	2,080	8,364	5,871	4,268	-
City Treasurer's investment pool [2]							
Money market funds	31,975	1,357	-	673	-	29,945	-
Federal agency securities	101,606	101,606	-	-	-	-	-
Corp medium term notes	31,718	-	-	26,184	-	5,534	-
State investment pool	52,048	-	-	-	-	-	52,048
Neg Certificate of Deposit	6,067	-	-	-	-	-	6,067
Total	$ 434,486	$ 159,411	$ 2,080	$ 35,221	$ 5,871	$ 39,747	$ 192,156

1 Amounts related to bond construction proceeds are invested in specific maturities but are available for construction of capital assets as funding is needed.
2 Additional information on investment types and credit risk may be found in the City's "Comprehensive Annual Financial Report."

NOTE 3. UTILITY PLANT

The following is a summary of changes in utility plant during the fiscal years ended June 30, 2013 and 2012 (in thousands):

	Balance As of 6/30/2011	Additions	Retirements/ Transfers	Balance As of 6/30/2012	Additions	Retirements/ Transfers	Balance As of 6/30/2013
Production [1, 2]	$ 426,575	$ 5,162	$ (82,473)	$ 349,264	$ -	$ (82,473)	$ 266,791
Transmission	29,152	2,902	-	32,054	3,122	-	35,176
Distribution	463,437	32,142	(661)	494,918	20,496	(1,078)	514,336
General	52,982	1,172	(361)	53,793	5,188	(154)	58,827
Intangibles	-	292	-	292	-	-	292
Depreciable utility plant	972,146	41,670	(83,495)	930,321	28,806	(83,705)	875,422
Less accumulated depreciation:							
Production [1, 2]	(159,467)	(11,316)	67,832	(102,951)	(10,191)	69,108	(44,034)
Transmission	(12,821)	(671)	-	(13,492)	(734)	-	(14,226)
Distribution	(160,366)	(12,577)	660	(172,283)	(13,480)	1,061	(184,702)
General	(19,689)	(2,913)	294	(22,308)	(2,987)	109	(25,186)
Intangibles		(5)		(5)	(58)	-	(63)
Accumulated depreciation	(352,343)	(27,482)	68,786	(311,039)	(27,450)	70,278	(268,211)
Net depreciable utility plant	619,803	14,188	(14,709)	619,282	1,356	(13,427)	607,211
Nuclear fuel, at amortized cost	4,878	4,907	(953)	8,832	1,317	(10,149)	-
Production [1, 2]	-	-	14,641	14,641	-	(14,641)	-
Land	7,645	9	-	7,654	29	-	7,683
Intangibles, non-amortizable	9,821	-	-	9,821	830	-	10,651
Construction in progress	39,787	45,771	(42,353)	43,205	37,970	(27,673)	53,502
Nondepreciable utility plant	57,253	45,780	(27,712)	75,321	38,829	(42,314)	71,836
Total utility plant	$ 681,934	$ 64,875	$ (43,374)	$ 703,435	$ 41,502	$ (65,890)	$ 679,047

1 SONGS Units 2 and 3 were taken offline in January 2012 and remained offline for extensive inspections, testing and analysis resulting from excessive wear of tubes in the steam generators. It was anticipated that Unit 2 would restart months in advance of Unit 3. Due to the uncertainty of Unit 3 restart date, the capital assets of Unit 3 were reclassified from a depreciable to a non-depreciable utility plant asset for fiscal year ended June 30, 2012.

2 On June 7, 2013 SCE announced its decision to permanently shut down both SONGS Units 2 and 3. As a result, both Units 2 and 3 have been written off from utility plant assets as an extraordinary item (Notes 7 and 10).

NOTE 4. LONG-TERM OBLIGATIONS

The following is a summary of changes in long-term obligations during the fiscal years ended June 30, 2013 and 2012 (in thousands):

	Balance As of 6/30/2011	Additions	Reductions	Balance As of 6/30/2012	Additions	Reductions	Balance As of 6/30/2013	Due Within One Year
Revenue bonds	$ 629,370	$ -	$ (26,247)	$ 603,123	$ -	$ (19,504)	$ 583,619	$ 20,685
Arbitrage liability	102	88	-	190	79	-	269	-
Advance from City - pension obligation	12,381	-	(378)	12,003	214	(436)	11,781	-
Postemployment benefits payable	2,775	1,034	-	3,809	1,060	-	4,869	-
Nuclear decommissioning liability	67,969	3,740	-	71,709	4,458	-	76,167	-
Capital leases	1,692	-	(389)	1,303	1,659	(412)	2,550	637
Loan payable	45,569	-	(1,428)	44,141	-	(1,480)	42,661	35,248
Compensated absences	4,271	3,496	(3,473)	4,294	3,609	(3,544)	4,359	3,597
Total long-term obligations	$ 764,129	$ 8,358	$ (31,915)	$ 740,572	$ 11,079	$ (25,376)	$ 726,275	$ 60,167

LOAN PAYABLE

The Utility entered into the Clearwater Power Plant Purchase and Sale Agreement dated March 3, 2010 with the City of Corona for the acquisition of Clearwater Cogeneration Facility (Clearwater) located in Corona. Clearwater is a combined-cycle, natural gas generating facility with a gross plant output of 29.5 megawatts (MW). Following a "transition period" during which the Utility engaged in pre-closing activities and due diligence inspection, the transaction closed on September 1, 2010 and the Utility took ownership of the plant. The purchase also included construction of a substation and the 69,000 volt facilities necessary to transfer power from Clearwater Power Plant to the SCE's electrical distribution system to California's high voltage transmission grid. The useful life of Clearwater and the related transmission facilities is anticipated to be at least thirty years. The total purchase price for Clearwater was $45,569, and will be funded through a series of remaining payments ranging from $181 to $413 from March 2014 through March 2015. In addition, two payments of $36,406 and $7,367 are due in September 2013 and 2015, respectively, and will be funded primarily from bond proceeds. See Note 12 for information on the subsequent event involving the prepayment of the Clearwater obligation.

NOTE 4. LONG-TERM OBLIGATIONS (CONTINUED)

Long-term debt consists of the following (in thousands):

REVENUE BONDS PAYABLE

	June 30, 2013	June 30, 2012
$75,405 2003 Electric Refunding/Revenue Bonds: serial bonds due in a final installment of $6,880 on October 1, 2013, interest of 4.6 percent	$ 6,880	$ 15,415
$27,500 2004 Electric Revenue Series A Bonds: serial bonds due in annual installments from $2,645 to $3,695 through October 1, 2014, interest from 5.0 to 5.5 percent	6,340	9,845
$141,840 2008 Electric Refunding/Revenue Bonds:		
A - $84,515 2008 Series A Bonds - variable rate bonds due in annual installments from $1,250 to $7,835 from October 1, 2014 through October 1, 2029. Interest rate is subject to weekly repricing (net interest rate, including swaps, at June 30, 2013 was 3.1 percent)	84,515	84,515
C - $57,325 2008 Series C Bonds - variable rate bonds due in annual installments from $700 to $5,200 through October 1, 2035. Interest rate is subject to weekly repricing (net interest rate, including swaps, at June 30, 2013 was 3.1 percent)	53,750	55,125
$209,740 2008 Electric Revenue Series D Bonds: fixed rate bonds due in annual installments from $3,460 to $25,345 from October 1, 2017 through October 1, 2038, interest from 3.6 to 5.0 percent	209,740	209,740
$34,920 2009 Electric Refunding/Revenue Series A Bonds: fixed rate bonds due in annual installments from $1,150 to $7,260 through October 1, 2018, interest from 3.0 to 5.0 percent	21,075	24,335
$140,380 2010 Electric Revenue Bonds:		
A - $133,290 2010 Electric Revenue Series A Bonds: fixed rate, federally taxable Build America Bonds due in annual installments from $2,300 to $33,725 from October 1, 2020 through October 1, 2040, interest from 3.9 to 4.9 percent	133,290	133,290
B - $7,090 2010 Electric Revenue Series B Bonds: fixed rate bonds due in annual installments from $95 to $2,440, from October 1, 2016 through October 1, 2019, interest from 3.0 to 5.0 percent	7,090	7,090
$56,450 2011 Electric Revenue/Refunding Series A Bonds: variable rate bonds due in annual installments from $725 to $5,175 through October 1, 2035. Interest rate is subject to weekly repricing (net interest rate, including swaps, at June 30, 2013 was 3.1 percent)	53,750	55,125
Total electric revenue bonds payable	576,430	594,480
Unamortized bond premium	7,189	8,643
Total electric revenue bonds payable, including bond premium	583,619	603,123
Less current portion of revenue bonds payable	(20,685)	(18,050)
Total long-term electric revenue bonds payable	$ 562,934	$ 585,073

Revenue bonds annual debt service requirements to maturity as of June 30, 2013 are as follows (in thousands):

	2014	2015	2016	2017	2018	2019-2023	2024-2028	2029-2033	2034-2038	2039-2041	Total
Principal	$ 20,685	$ 14,480	$ 15,415	$ 12,745	$ 13,170	$ 73,335	$ 88,305	$ 108,250	$ 133,575	$ 96,470	$ 576,430
Interest	$ 24,619	$ 23,745	$ 23,113	$ 22,620	$ 22,201	$ 103,178	$ 87,530	$ 66,841	$ 40,213	$ 7,314	421,374
Total	$ 45,304	$ 38,225	$ 38,528	$ 35,365	$ 35,371	$ 176,513	$ 175,835	$ 175,091	$ 173,788	$ 103,784	$ 997,804

The Utility's bond indentures require the Utility to maintain a minimum debt service coverage ratio, as defined by the bond covenants of 1.10. The Utility's debt service coverage ratio was 2.73 and 2.24 at June 30, 2013 and 2012, respectively. The Utility's revenue bonds are backed by the revenues of the Utility.

INTEREST RATE SWAPS ON REVENUE BONDS

The Utility has three cash flow hedging derivative instruments, which are pay-fixed swaps. These swaps were employed as a hedge against debt that was refunded in 2008 and 2011. At the time of the refunding, hedge accounting ceased to be applied. The balance of the deferral account for each swap is included as part of the deferred loss on refunding associated with the new bonds. The swaps were also employed as a hedge against the new debt. Hedge accounting was applied to that portion of the hedging relationship, which was determined to be effective. The negative fair value of the interest rate swaps related to the new hedging relationship has been recorded and deferred on the Statements of Net Position.

A summary of the derivative activity for the year ended June 30, 2013 is as follows:

	Notional Amount	Fair Value as of 6/30/2013	Change in Fair Value for Fiscal Year
2008 Electric Refunding/Revenue Bonds Series A	$ 84,515	$ (9,645)	$ 5,340
2008 Electric Refunding/Revenue Bonds Series C	$ 57,325	$ (7,056)	$ 4,528
2011 Electric Refunding/Revenue Bonds Series A	$ 56,450	$ (7,028)	$ 4,526

Objective: In order to lower borrowing costs as compared to fixed-rate bonds, the Utility entered into interest rate swap agreements in connection with its $141,840 2008 Electric Refunding/Revenue Bonds (Series A and C) and $56,450 2011(Series A).

Terms: Per the existing swap agreements, the Utility pays the counterparty a fixed payment and receives a variable payment computed as 62.68% of the London Interbank Offering Rate ("LIBOR") one month index plus 12 basis points. The swaps have notional amounts equal to the principal amounts stated above. The notional value of the swaps and the principal amounts of the associated debt decline by $1,250 to $7,835 (2008 Series A), $700 to $5,200 (2008 Series C) and $725 to $5,175 (2011 Series A) until the debt is completely retired in fiscal years 2030 (2008 Series A) and 2036 (2008 Series C and 2011 Series A).

The bonds and the related swap agreements for the Electric Refunding/Revenue 2008 (Series A) Bonds mature on October 1, 2029 and the 2008 (Series C) and 2011 (Series A) Bonds mature on October 1, 2035. As of June 30, 2013, rates were as follows:

		2008 Electric Refunding/Revenue Series A Bonds	2008 Electric Refunding/Revenue Series C Bonds	2011 Electric Refunding/Revenue Series A Bonds
Interest rate swap:	Terms	Rates	Rates	Rates
Fixed payment to counterparty	Fixed	3.11100%	3.20400%	3.20100%
Variable payment from counterparty	62.68 LIBOR + 12bps	(0.46286%)	(0.46435%)	(0.26036%)
Net interest rate swap payments		2.64814%	2.73965%	2.94064%
Variable-rate bond coupon payments		0.40854%	0.40613%	0.15723%
Synthetic interest on bonds		3.05668%	3.14578%	3.09787%

Fair value: As of June 30, 2013, in connection with all swap agreements, the transactions had a total negative fair value of ($23,729). Because the coupons on the Utility's variable-rate bonds adjust to changing interest rates, the bonds do not have a corresponding fair value decrease. The fair value was developed by a pricing service using the zero-coupon method. This method calculates the future net settlement payments required by the swaps, assuming that the current forward rates implied by the yield curve correctly anticipate future spot interest rates. These payments are then discounted using the spot rates implied by the current yield curve for hypothetical zero-coupon bonds due on the date of each future net settlement of the swap.

Credit risk: As of June 30, 2013, the Utility was not exposed to credit risk because the swaps had a negative fair value. The swaps counterparties, J.P. Morgan Chase & Co and Merrill Lynch were rated A and A-, respectively by Standard & Poor's. To mitigate the potential for credit risk, the swap agreements require the fair value of the swaps to be collateralized by the counterparty with U.S. Government securities if the counterparties' rating decreases to negotiated trigger points. Collateral would be posted with a third-party custodian. At June 30, 2013, there is no requirement for collateral posting for any of the outstanding swaps.

NOTE 4. LONG-TERM OBLIGATIONS (CONTINUED)

Basis risk: As noted above, the swaps expose the Utility to basis risk should the relationship between LIBOR and the variable interest rates converge, changing the synthetic rate on the bonds. If a change occurs that results in the rates moving to convergence, the expected cost savings may not be realized.

Termination risk: The derivative contract uses the International Swap Dealers Association Master Agreement, which includes standard termination events, such as failure to pay and bankruptcy. The Schedule to the Master Agreement includes an "additional termination event." That is, a swap may be terminated by the Utility if either counterparty's credit quality falls below "BBB-" as issued by Standard & Poor's. The Utility or the counterparty may terminate a swap if the other party fails to perform under the terms of the contract. If a swap is terminated, the variable-rate bond would no longer carry a synthetic interest rate. Also, if at the time of termination a swap has a negative fair value, the Utility would be liable to the counterparty for a payment equal to the swap's fair value.

Swap payments and associated debt: As of June 30, 2013, the debt service requirements of the variable-rate debt and net swap payments, assuming current interest rates remain the same for their term, are summarized as follows. As rates vary, variable-rate bond interest payments and net swap payments will vary.

Fiscal Year Ending June 30,	Variable-Rate Bonds Principal	Interest	Interest Rate Swaps, Net	Total
2014	$ 2,850	$ 640	$ 5,210	$ 8,700
2015	4,800	625	5,076	10,501
2016	12,275	585	4,736	17,596
2017	11,500	547	4,417	16,464
2018	6,150	525	4,251	10,926
2019-2023	41,425	2,199	18,043	61,667
2024-2028	37,875	1,459	12,643	51,977
2029-2033	45,115	689	6,835	52,639
2034-2036	30,025	87	873	30,985
Total	$ 192,015	$ 7,356	$ 62,084	$ 261,455

NOTE 5. RESTRICTED NET POSITION

Pursuant to applicable bond indentures, a reserve for debt service has been established by restricting assets and reserving a portion of net position. Bond indentures for the Utility's electric revenue and refunding bonds require debt service reserves that equate to the maximum annual debt service required in future years and bond service reserves of three months interest and nine months principal due in the next fiscal year. Variable rate revenue and refunding bonds require 110% of the monthly accrued interest to be included in the reserve. Active electric revenue bonds requiring reserves are issues 2003, 2004A, and 2008A & C. Certain revenue/refunding bond issues are covered by a Surety Bond (2008D) and certain issues have no debt service reserve requirements (2009A, 2010A & B and 2011A).

NOTE 6. JOINTLY-GOVERNED ORGANIZATIONS

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

On November 1, 1980, the City joined with the Imperial Irrigation District and the cities of Los Angeles, Anaheim, Vernon, Azusa, Banning, Colton, Burbank, Glendale and Pasadena to create the Southern California Public Power Authority (SCPPA) by a Joint Powers Agreement under the laws of the State of California. As of July 2001, the City of Cerritos was admitted as an additional member of the SCPPA. The primary purpose of SCPPA is to plan, finance, develop, acquire, construct, operate and maintain projects for the generation and transmission of electric energy for sale to its participants. SCPPA is governed by a Board of Directors, which consists of one representative from each of the members. During the 2012-13 and 2011-12 fiscal years, the Utility paid approximately $16,171 and $20,855, respectively, to SCPPA under various take-or-pay contracts that are described in greater detail in Note 8. These payments are reflected as a component of production and purchased power and transmission expenses in the financial statements.

POWER AGENCY OF CALIFORNIA

On July 1, 1990, the City joined with the cities of Azusa, Banning and Colton to create the Power Agency of California (PAC) by a Joint Powers Agreement under the laws of the State of California. The City of Anaheim joined PAC on July 1, 1996. The primary purpose of PAC is to take advantage of synergies and economies of scale as a result of the five cities acting in concert. PAC has the ability to plan, finance, develop, acquire, construct, operate and maintain projects for the generation and transmission of electric energy for sale to its participants. PAC is governed by a Board of Directors, which consist of one representative from each of the members. The term of the Joint Powers Agreement is 50 years. Effective June 30, 2001, PAC was placed in an inactive status by the Board of Directors and can only be reactivated by authorization of the Agency Board.

NOTE 7. JOINTLY-OWNED UTILITY PROJECT – SONGS

The City has a 1.79% undivided ownership interest in Units 2 and 3 of SONGS, located south of the City of San Clemente in northern San Diego County; however, on June 7, 2013, SCE announced in a press release its plan to retire Units 2 and 3 of SONGS permanently. Consequently, the units are no longer a source of supply for the Utility, but remain associated with certain of its costs, including those associated with the units' shutdown and decommissioning (see Note 1 for nuclear decommissioning liability).

Units 2 and 3 of SONGS became operational on October 9, 1983 and April 1, 1984, respectively. The City's share of the original construction costs plus subsequent ongoing betterments was approximately $165 million, which was financed mainly through revenue bonds. In the fiscal year ended June 30, 2012, SONGS provided 191,900 MWh of energy to the City at an average cost of 13.6 cents per kilowatt (kWh), exclusive of delivery costs.

SONGS was operated and maintained by SCE, under an agreement with the City and San Diego Gas & Electric Company (SDG&E), that expires upon termination of the easement for the plant in 2024. The three-member SONGS Board of Review approved the budget for capital expenditures and operating expenses. The City and the two other owners each had one representative on that board. The participation agreement provided that each owner was entitled to its proportionate share of benefits of, and paid its proportionate share of costs and liabilities incurred by SCE for, construction, operation and maintenance of the project; each owner's obligation was several, and not joint or collective. The City's influence to control or manage SONGS was limited at times because the City does not have a controlling interest.

The capacity previously available to the City from SONGS Units 2 and 3 was 19.2 MW and 19.3 MW, respectively. SONGS has a nominal net generating capability of 2,150 MW. The other owners are SCE, with a 78.21% interest (including the 3.16% interest it acquired from Anaheim in 2006), and SDG&E, with a 20.00% interest.


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Public Utilities

NOTE 7. JOINTLY-OWNED UTILITY PROJECT – SONGS (CONTINUED)

In 2005, the California Public Utilities Commission (CPUC) authorized a project to install four new steam generators in Units 2 and 3 at SONGS and remove and dispose of the predecessor generators. SCE completed the installation of these steam generators in 2010 and 2011 for Units 2 and 3, respectively. The City's share of the cost to replace the steam generators was approximately $13.4 million. Replacement of the steam generators was expected to enable plant operations to continue through at least 2022, and perhaps beyond, subject to the approval of the Nuclear Regulatory Commission (NRC).

In January 2012, a water leak occurred in one of the heat transfer tubes of Unit 3's steam generators, causing it to be shut down. At that time, Unit 2 was off-line for a planned outage when unexpected wear in areas of tube-to-support structure were found. Units 2 and 3 remained off-line for extensive inspections, testing and analysis of their steam generators. Due to challenges encountered during the regulatory process to bring the units back into operation, on June 7, 2013 SCE unilaterally announced its plan to retire Units 2 and 3 permanently.

The current plant site easement for SONGS terminates on May 12, 2024 and would be need to be extended in order for the plant to be decommissioned and the site restored.

Replacement Power Costs. During the outage, the City has procured replacement power to serve its customers' requirements. These costs are in addition to the usual approximate $11.5 million in operating and maintenance expenses paid annually during normal operations. Replacement power costs incurred by the City as a result of the outage (commencing on January 31, 2012 for Unit 3 and March 5, 2012 for Unit 2) through June 30, 2013 were approximately $13.2 million and are reflected as regulatory assets on the Statements of Net Position.

Contractual Matters. The replacement steam generators for Units 2 and 3 were designed and manufactured by Mitsubishi Heavy Industries (MHI) and were warranted for an initial period of 20 years from acceptance. MHI was contractually obligated to repair or replace defective items and to pay specified damages for certain repairs. On July 18, 2012, the NRC issued a report providing the result of the inspection performed by the Augmented Inspection Team. The inspection concluded that faulty computer modeling that inadequately predicted conditions in the steam generators at SONGS and manufacturing issues contributed to excessive wear of the components. This report also identified a number of still unresolved issues that are continuing to be examined. MHI's liability under the purchase agreement is limited to $138 million and excludes consequential damages, defined to include "the cost of replacement power." The limitations are subject to certain exceptions. SCE has reported that the disagreement with MHI as to whether MHI's liability is not limited to $138 million may ultimately become subject to dispute resolution procedures contained in the purchase agreement, including international arbitration. SCE, on behalf of itself and the other SONGS co-owners, has submitted five invoices to MHI totaling $139 million for steam generator repair costs incurred through February 28, 2013. MHI paid the first invoice of $45 million (of which the City has received its proportional share of $812), while reserving its right to challenge any of the charges in the invoice. In January 2013, MHI advised SCE that it rejected a portion of the first invoice and required further documentation regarding the remainder of it. The City expects to receive its proportional share of any recovery that SCE receives from MHI.

There are insurance policies for both property damage and accidental outage issued by Nuclear Electric Insurance Limited (NEIL), and SCE has notified NEIL of claims under the two policies. The City is a named insured on the SCE insurance policies covering SONGS and will assist SCE in pursuing claims recoveries from NEIL, as well as warranty claims with MHI, but there is no assurance that the City will recover all or any of its applicable costs under these arrangements. To the extent that any third-party recoveries are made, they will reduce cost to the Utility. At this time, the City continues to collect from customers, through its rates, the City's share of the operating costs related to SONGS.

According to a news release issued by SCE on July 18, 2013, SCE served a formal Notice of Dispute on MHI and Mitsubishi Nuclear Energy Systems and initiated a 90-day dispute resolution process under the purchase agreement. On July 18, 2013, the City filed a lawsuit against MHI for breach of contract, negligence and misrepresentation in San Diego County Superior Court (Note 9). On July 24, 2013, MHI moved the lawsuit to the United States District Court for the Southern District of California.

NOTE 8. COMMITMENTS

TAKE-OR-PAY CONTRACTS

The Utility has entered into a power purchase contract with Intermountain Power Agency (IPA) for the delivery of electric power. The Utility's share of IPA power is equal to 7.6 percent, or approximately 137.1 MW, of the net generation output of IPA's 1,800 MW coal-fueled generating station located in central Utah. The contract expires in 2027 and the debt fully matures in 2024.

The contract constitutes an obligation of the Utility to make payments solely from operating revenues. The power purchase contract requires the Utility to pay certain minimum charges that are based on debt service requirements and other fixed costs. Such payments are considered a cost of production.

The Utility is a member of SCPPA, a joint powers agency (see Note 6). SCPPA provides for the financing and construction of electric generating and transmission projects for participation by some or all of its members. To the extent the Utility participates in projects developed by SCPPA, it has entered into Power Purchase or Transmission Service Agreements, entitling the Utility to the power output or transmission service, as applicable, and the Utility will be obligated for its proportionate share of the project costs whether or not such generation output of transmission service is available.

The projects and the Utility's proportionate share of SCPPA's obligations, including final maturities and contract expirations are as follows:

Project	Percent Share	Entitlement	Final Maturity	Contract Expiration
Palo Verde Nuclear Generating Station	5.4 percent	12.3 MW	2017	2030
Southern Transmission System	10.2 percent	244.0 MW	2027	2027
Hoover Dam Uprating	31.9 percent	30.0 MW	2017	2017
Mead-Phoenix Transmission	4.0 percent	18.0 MW	2020	2030
Mead-Adelanto Transmission	13.5 percent	118.0 MW	2020	2030

As part of the take-or-pay commitments with IPA and SCPPA, the Utility has agreed to pay its share of current and long-term obligations. Management intends to pay these obligations from operating revenues received during the year that payment is due. A long–term obligation has not been recorded on the accompanying financial statements for these commitments. Take-or-pay commitments terminate upon the later of contract expiration or final maturity of outstanding bonds for each project.

Outstanding debts associated with the take-or-pay obligations have variable interest rates for the Palo Verde Nuclear Generating Station Project and portions of the Mead Phoenix and Mead Adelanto Projects. The remaining projects have fixed interest rates which range from 0.35 percent to 6.13 percent. The schedule below details the amount of principal and interest that is due and payable by the Utility as part of the take-or-pay contract for each project in the fiscal year indicated.

	IPA	SCPPA					TOTAL
Debt Service Payment (in thousands) Year Ending June 30,	Intermountain Power Project	Palo Verde Nuclear Generating Station	Southern Transmission System	Hoover Dam Uprating	Mead-Phoenix Transmission	Mead-Adelanto Transmission	All Projects
2014	$ 6,876	$ 664	$ 8,181	$ 705	$ 333	$ 3,273	$ 20,032
2015	21,289	668	8,335	703	277	3,141	34,413
2016	21,965	672	9,823	701	261	2,959	36,381
2017	17,825	675	6,685	701	262	2,952	29,100
2018	16,398	679	7,980	699	258	2,910	28,924
2019-2023	78,898	-	40,141	-	700	7,877	127,616
2024-2028	6,019	-	22,101	-	-	-	28,120
Total	$ 169,270	$ 3,358	$ 103,246	$ 3,509	$ 2,091	$ 23,112	$ 304,586

In addition to debt service, the Utility's entitlements require the payment of fuel costs, operating and maintenance, administrative and general and other miscellaneous costs associated with the generation and transmission facilities discussed above. These costs do not have a similar structured payment schedule as debt service and vary each year. The costs incurred for the year ended June 30, 2013 and 2012, are as follows (in thousands):

FISCAL YEAR	Intermountain Power Project	Palo Verde Nuclear Generating Station	Southern Transmission System	Hoover Dam Uprating	Mead-Phoenix Transmission	Mead-Adelanto Transmission	All Projects
2013	$ 26,445	$ 2,528	$ 2,405	$ 97	$ 41	$ 338	$ 31,854
2012	$ 22,555	$ 2,843	$ 2,677	$ 102	$ 40	$ 300	$ 28,517

These costs are included in production and purchased power or transmission expense on the Statements of Revenues, Expenses and Changes in Net Position.

The Utility has become a Participating Transmission Owner (PTO) with the California Independent System Operator (CAISO) (see Note 9) and has turned over the operational control of its transmission entitlements including the Southern Transmission System, Mead-Phoenix and Mead-Adelanto Transmission Projects. In return, users of the California's high voltage transmission grid are charged for, and the Utility receives reimbursement for, its transmission revenue requirements (TRR), including the costs associated with these three transmission projects.

HOOVER UPRATING PROJECT

The Hoover Uprating Project has contractors from Arizona, Nevada, and California. Over the past two years, the contractors have been meeting to negotiate terms for the renewal of contracts for electric services, which are set to expire on September 30, 2017. The contractors developed proposed legislation, that became known as the Hoover Power Allocation Act, which would extend the availability of Hoover power to the existing contractors for an additional fifty years and create a pool for new entrants.

In December 2011, President Obama signed the Hoover Power Allocation Act of 2011 which provides for the extension of the existing contract for an additional 50 years from 2017 to 2067. The new Legislation requires the Utility to relinquish 5% (1.5 MW) of their current power for a new entitlement of 28.5 MW, effective October 1, 2017. The power relinquished will be used to create a new resource pool equal to 5% of the full rated capacity of 2,074,000 kilowatts (KW), and associated firm energy, and would be allocated to new entities as follows: two-thirds to the Western Area Power Administration and one-third allocated equally to new contractors in Nevada, California and Arizona including federally recognized Indian tribes that do not currently purchase Hoover power. The new entities will be required to execute the Boulder Canyon Project Implementation Agreement which will include a provision requiring them to pay a proportionate share of their State's respective contribution to the cost of the Lower Colorado River Multi-Species Conservation Program and the Uprate Program. Any of the capacity and firm energy not allocated to the new entities and not placed under contract by October 1, 2017, will be returned to the existing contractors in the same proportion as the contractor's allocations. The Utility's cost incurred for the Multi-Species Conservation Program will be reduced and the Utility will receive reimbursement for a proportionate share of the uprating costs.

POWER PURCHASE AGREEMENTS

The Utility has one firm power purchase agreement (PPA) with Bonneville Power Administration (BPA) for the purchase of capacity 50 MW during the summer months and 13 MW during the winter months beginning April 30, 1996, for 20 years. Effective May 1, 1998, these summer and winter capacity amounts increased to 60 MW and 15 MW, respectively, for the remainder of the second agreement. On January 29, 2013, the Utility revised the delivery and return portion of the agreement to allow for a flat 40 MW of delivery during May and June through calendar year 2013, 2014 and 2015. The agreement with BPA will terminate on May 1, 2016.

NOTE 8. COMMITMENTS (CONTINUED)

NUCLEAR INSURANCE

The Price-Anderson Act (the Act) requires that all utilities with nuclear generating facilities purchase the maximum private primary nuclear liability insurance available ($375 million) and participate in the industry's secondary financial protection plan. The secondary financial protection program is the industry's retrospective assessment plan that uses deferred premium charges from every licensed reactor owner if claims and/or costs resulting from a nuclear incident at any licensed reactor in the United States were to exceed the primary nuclear insurance at that plant's site. Effective September 10, 2013, the Act limits liability from third-party claims to approximately $13.6 billion per incident. Under the industry wide retrospective assessment program provided for under the Act, assessments are limited to $127.3 million per reactor for each nuclear incident occurring at any nuclear reactor in the United States, with payments under the program limited to $19.0 million per reactor, per year, per event to be indexed for inflation every five years. Based on the Utility's interest in Palo Verde and ownership in SONGS, the Utility would be responsible for a maximum assessment of $25.2 million, limited to payments of $3.8 million per incident, per year. If the public liability limit above is insufficient, federal regulations may impose further revenue-raising measures to pay claims, including a possible additional assessment on all licensed reactor operators.

RENEWABLE PORTFOLIO STANDARD (RPS)

On April 12, 2011, the California Renewable Energy Resources Act (SBX1-2) was passed by the State Legislative and signed by the Governor. SBX1-2 revised the amount of statewide retail electricity sales from renewable resources in the State Renewable Energy Resources Program to 33% by December 31, 2020 in three stages: average of 20% of retail sales during 2011-2013; 25% of retail sales by December 31, 2016; and 33% of retail sales by December 31, 2020. The Riverside Public Utilities Board and City Council approved the enforcement program required by SBX1-2 on November 18, 2011 and December 13, 2011, respectively, and further approved the Utility's RPS Procurement Plan implementing the new RPS mandates on May 3, 2013 and May 14, 2013, respectively. It is expected that the Utility will be able to meet the new mandates with new resource procurement actions as outlined in the City's RPS Procurement Plan. For Calendar year 2012, renewable resources provided 20% of retail sales requirements.

In an effort to increase the share of renewables in the Utility's power portfolio, the Utility entered into PPAs with various entities described below on a "take-and-pay" basis. The contracts in the following table were executed as part of compliance with this standard.

Long-term renewable PPAs (in thousands):

Supplier	Type	Maximum Contract [1]	Contract Expiration	Estimated Annual Cost For 2014
Salton Sea Power LLC	Geothermal	46.0 MW	5/31/2020	$ 24,170
CalEnergy	Geothermal	86.0 MW	12/31/2039	-
Wintec	Wind	1.3 MW	12/30/2018	209
WKN Wagner	Wind	6.0 MW	12/22/2032	1,100
AP North Lake	Photovoltaic	20.0 MW	[2]	-
Silverado Power			[2]	
Summer Solar	Photovoltaic	20.0 MW	[2]	-
Antelope Big Sky Ranch	Photovoltaic	20.0 MW	[2]	-
Total		199.3 MW		$ 25,479

1 All contracts are contingent on energy production from specific related generating facilities. The Utility has no commitment to pay any amounts except for energy produced on a monthly basis from these facilities.

2 Power purchase agreements have a 25-year term. The contract expiration dates are 25 years from the commercial operation of the power plant. The plants are expected to become commercially operational by January 1, 2015, but in no event later than December 31, 2015.

On August 23, 2005, the City Council approved an amendment to the PPA between Salton Sea and the Utility. The agreement increases the amount of renewable energy available to the Utility from 20 MW to 46 MW effective June 1, 2009 through May 31, 2020. The pricing under the Salton Sea PPA was amended on May 14, 2013 to conform to pricing in the new PPA with CalEnergy (discussed below) through the remaining term of the Salton Sea PPA. The price increased by $7.57 per MWh to $69.66, reflecting the exchange of benefits for a substantial lower price under the new PPA. The cost increase under the Salton Sea PPA is approximately $2.7 million per year for the agreement's remaining term.

On May 14, 2013, the City Council approved a new 25-year PPA with CalEnergy, the parent of Salton Sea, for additional renewable geothermal power. The PPA provides power from a portfolio of ten geothermal generating units, instead of a single generating unit, with an increasing amount of delivery starting with 20 MW in 2016 and increasing to 40 MW in 2019 and 86 MW in 2021. The PPA is expected to provide 7.5%, 15% and 30% of the City's total power demand in 2016, 2019, 2021, respectively. The price under the agreement will be $72.85 per MWh in calendar year 2016 and escalate at 1.5% annual for the remaining term of the agreement. Similar to other renewable PPAs, the Utility is only obligated for purchases of energy delivered to the City.

On November 10, 2006, the Utility entered into a second renewable PPA with Wintec Energy, Ltd (Wintec) for wind generation capacity of up to 8.0 MW on their proposed Wintec Facility II Wind Turbine Project. The contract term is for 15 years, expiring November 10, 2021. The developer is encountering challenges in finding suitable wind turbines to complete the project and the project is expected to continue to be delayed. The Utility does not expect to receive more than 1.3 MW from Wintec per the original contract which expires in December 2018. Due to the delay of the proposed Wintec Facility II Wind Turbine Project, on February 7, 2012, Wintec entered into an Assignment Agreement with WKN Wagner, LLC (WKN) for the purpose of assigning to WKN all of Wintec's right, title, and interest in the Renewable PPA dated November 10, 2006. The Utility was in agreement with the Assignment and entered into a new PPA with WKN under the same commercial terms and conditions as in the original agreement with Wintec, except that the term has been extended to 20 years, instead of 15. WKN completed the project development timely, and the project became commercially operational on December 22, 2012 and is expected to contribute 1% of the City's retail load requirements.

On October 16, 2012, the City entered into a 25-year PPA with AP North Lake, LLC (AP North) for 20 MW of solar photovoltaic energy generated by a new facility located in the City of Hemet, California. The AP North project is expected to become commercially operational by January 1, 2015, but in no event later than December 31, 2015. The project is expected to generate 55,000 MWh of renewable energy per year at a levelized cost of $95 per MWh for the term of the PPA.

On January 8, 2013, the City entered into two 25-year PPAs for a combined total of 40 MW of solar photovoltaic energy generated by two facilities to be built by Silverado Power in the City of Lancaster, California. The two projects are referred to as Antelope Big Sky Ranch and Summer Solar, each rated at 20 MW. The City will have a 50% share of the output from each project through SCPPA. The Silverado projects are expected to become commercially operational by January 1, 2015, but in no event later than December 31, 2015. The City's share from the two projects is 55,000 MWh of renewable energy per year at a levelized cost of $93.4 per MWh for the term of the PPAs.

CONSTRUCTION COMMITMENTS

As of June 30, 2013, the Utility had major commitments (encumbrances) of approximately $14,722 with respect to unfinished capital projects, of which $13,368 is expected to be funded by bonds and $1,354 funded by rates.

FORWARD PURCHASE/SALE AGREEMENTS

In order to meet summer peaking requirements, the Utility may contract on a monthly or quarterly basis, for the purchase or sale of natural gas, electricity and/or capacity products on a short term horizon. As of June 30, 2013, the Utility has net commitments for fiscal year 2014 and thereafter, of approximately $24,770, with a market value of $22,508.

NOTE 9. LITIGATION

The Utility is a defendant in various lawsuits arising in the normal course of business. Present lawsuits and other claims against the Utility are incidental to the ordinary course of operations of the Utility and are largely covered by the City's self-insurance program. In the opinion of management and the City Attorney, such claims and litigation will not have a materially adverse effect upon the financial position or results of operation of the Utility.

On July 18, 2013, the City filed a lawsuit against MHI for breach of contract, negligence and misrepresentation in San Diego County Superior Court related to the replacement steam generators installed at SONGS. No arbitration date or trial date has been scheduled. See Note 7 for information on contractual and litigation matters for SONGS.

CALIFORNIA ENERGY CRISIS SETTLEMENT

During the California Energy Crisis of 2001-2002, the Utility made numerous power sales into the California centralized markets. Due to financial problems experienced by numerous market participants, notably Pacific Gas & Electric (PG&E) and the California Power Exchange (Cal PX), who filed for Chapter 11 bankruptcy in 2001, the Utility was not paid for many of these transactions. On June 4, 2008, the FERC approved a settlement agreement between the Utility and numerous California entities, including all of the Investor-Owned Utilities and the California Attorney General, under which the Utility was paid all of its unpaid receivables, plus interest, minus $1.27 million in refunds. The net payout to the Utility was $3.7 million (including all unpaid receivables, including interest and its deposit with the Cal PX, minus $269 thousand paid to the City of Banning for transactions made on its behalf by the Utility). Under the settlement, the Utility may receive additional distributions of refunds from other sellers. The Utility also may be responsible for paying its allocated portion, as determined by FERC, of payments due to other sellers for any Emission Offset, Fuel Cost Allowance, or Cost Offset associated with sales by such other sellers during the energy crisis. It is not possible at this time to estimate the net effect of any such future distributions to or payments by the Utility.

TRANSMISSION REVENUE REQUIREMENT (TRR) FILING

The Utility continues to participate in key FERC dockets impacting the Utility, such as the CAISO's Market Redesign and Technology Upgrade (MRTU). On January 1, 2003, the Utility became a PTO with the CAISO, entitling the Utility to receive compensation for use of its transmission facilities committed to the CAISO's operational control. The compensation is based on the Utility's TRR as approved by the FERC.

On July 1, 2011, the Utility filed a revised TRR at FERC. In its filing, the Utility updated its projected transmission costs and confirmed the Utility's ability to automatically recover further cost increases imposed by SCE without filing an application with FERC for a new TRR tariff. On December 19, 2011, FERC approved the Utility's new TRR of $29,415, an increase of $3,900 from the previous TRR of $25,515. The new TRR became effective August 1, 2011.

On May 11, 2004, the CAISO filed Amendment No. 60 to its Tariff to modify the CAISO's process for dispatching generation and allocating associated costs. Numerous parties, including the Utility as a member of the "Southern Cities" group, submitted testimony to the FERC on the allocation of these costs, and a hearing was held in 2005. On October 31, 2005, the Presiding Administrative Law Judge issued an Initial Decision, and on December 27, 2006, the FERC issued an order generally affirming the determinations in the Initial Decision. The FERC order adopted the Utility's position with respect to "South-of-Lugo" costs, which would have resulted in a large part of these generation dispatch costs being allocated to SCE. On November 20, 2007, the FERC issued its Order on Rehearing, reversing its position on South-of-Lugo costs in a manner that would require the Utility to share these costs. The Utility and a number of other parties filed requests for rehearing of the Order on Rehearing. On September 16, 2011, FERC issued an Order Denying Rehearing of the Order on Rehearing. The Utility and other parties filed a petition for review with the Appellate Court on November 14, 2011. The outcome of the appeal and the ultimate resolution is unknown at this time. Due to the complicated process for calculating cost allocations, if the appeal is granted or denied, it is impossible at this time to estimate the Utility's likely cost exposure.

NOTE 10. EXTRAORDINARY ITEM

On June 7, 2013, SCE announced its decision to permanently retire SONGS Units 2 and 3. Consequently, the units are no longer a source of supply for the Utility. As a result, SONGS Units 2 and 3 with a net book value of $29,075 are considered impaired and written off from Utility Plant assets on the Statements of Net Position. The associated nuclear fuel with a net book value of $10,149 and nuclear materials inventory with a net book value of $ 2,035 are also considered impaired and written off from the Statements of Net Position. The total loss of $41,259 is reported as an extraordinary item on the Statements of Revenues, Expenses and Changes in Net Position as of June 30, 2013.

NOTE 11. ACCOUNTING CHANGE

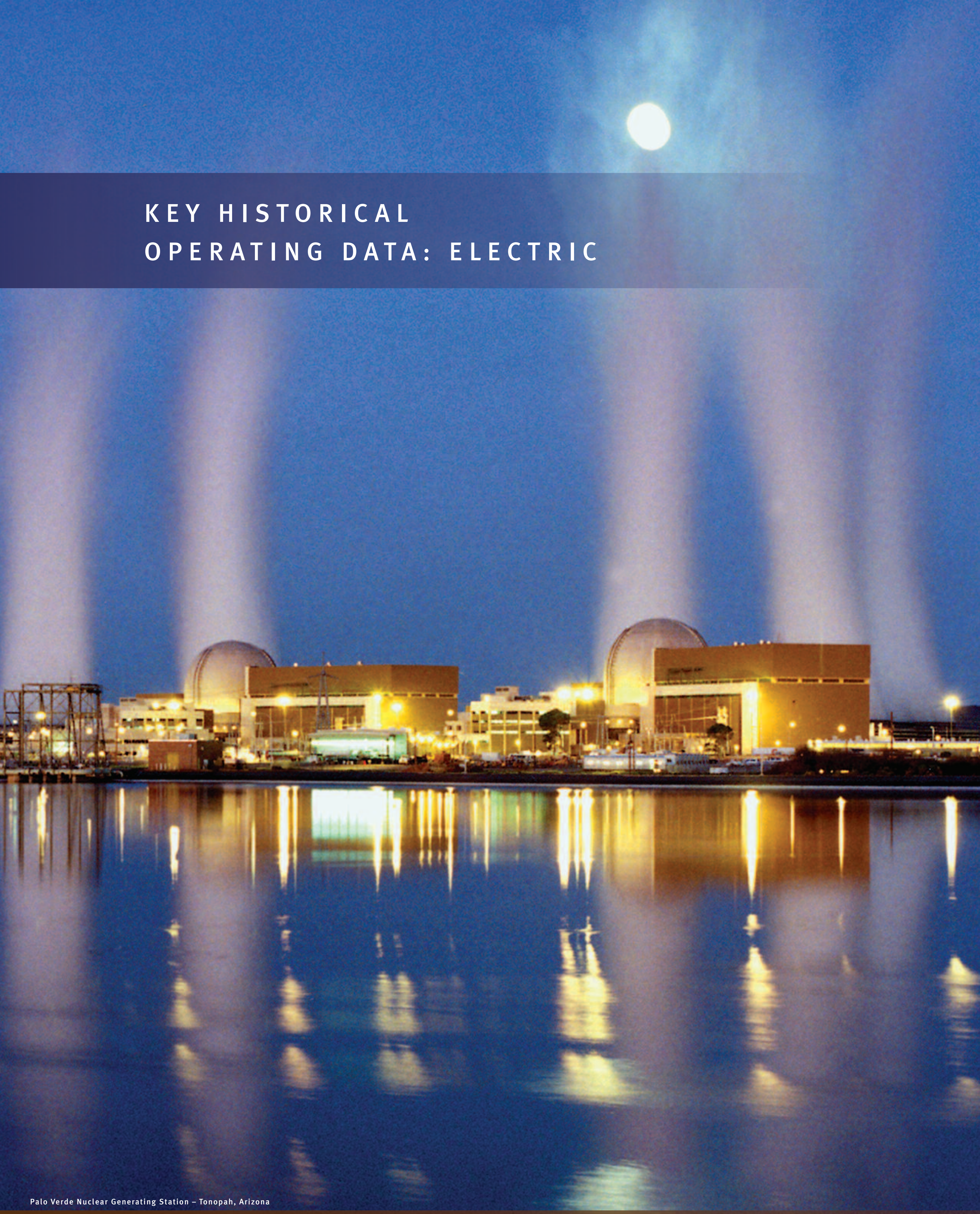
The accompanying financial statements reflect the implementation of GASB Statement No. 63, *Financial Reporting of Deferred Outflows of Resources, Deferred Inflows of Resources, and Net Position* (GASB 63), and GASB Statement No. 65, *Items Previously Reported as Assets and Liabilities* (GASB 65). Significant impacts of GASB 63 include changing the title of the Balance Sheets to Statements of Net Position, changing the title of equity section to net position and reformatting the Statements of Net Position to add separate sections for deferred outflows of resources and deferred inflows of resources. Significant impacts of GASB 65 include reclassifying as deferred outflows of resources and deferred inflows of resources certain balances that were previously reported as assets and liabilities.

NOTE 12. SUBSEQUENT EVENT

2013 Electric Revenue Refunding Bonds

On July 25, 2013 the Utility issued $79,080 of 2013 Electric Revenue Refunding Series A Bonds and $780 of Taxable Electric Revenue Series B Bonds. The bonds were issued to prepay the outstanding obligation to the City of Corona related to the Clearwater Power Plant; to refund certain outstanding variable rate bonds; and to pay a portion of the termination cost associated with the interest rate swaps allocated or related to the refunded portions of the applicable bonds. Interest on the Series A bonds is payable semi-annually on April 1 and October 1, commencing October 1, 2013. Principal is due in annual installments from $175 to $12,685 through October 1, 2043. The rate of interest varies from 3% to 5.25% per annum. Series B bonds, with an interest rate of 0.5%, is due in one installment of $780 on October 1, 2013.

KEY HISTORICAL OPERATING DATA: ELECTRIC



Palo Verde Nuclear Generating Station – Tonopah, Arizona

KEY HISTORICAL OPERATING DATA

POWER SUPPLY (MWH)

	2012/13	2011/12	2010/11	2009/10	2008/09
Nuclear					
San Onofre	0	191,900	284,900	240,000	281,400
Palo Verde	102,300	101,100	102,000	96,300	97,700
Coal					
Intermountain Power	754,900	799,700	895,600	1,068,500	1,051,200
Deseret	0	0	0	187,400	406,000
Hoover (Hydro)	32,500	35,300	32,900	30,000	32,500
Gas					
Springs	5,500	2,300	3,100	1,400	3,300
RERC	77,700	39,400	34,500	11,500	48,700
Clearwater	24,000	17,000	9,700	0	0
Renewable Resources	444,300	472,300	385,700	354,900	233,000
Other purchases	937,500	620,000	464,200	276,500	349,200
Exchanges In	95,800	75,200	92,200	92,700	90,000
Exchanges Out	(134,900)	(133,500)	(176,100)	(156,200)	(160,600)
Total	2,339,600	2,220,700	2,128,700	2,203,000	2,432,400
System peak (MW)	591.7	581.2	579.7	560.3	534.1

ELECTRIC USE

	2012/13	2011/12	2010/11	2009/10	2008/09
Number of meters as of year end					
Residential	96,207	95,988	95,676	95,258	95,214
Commercial	10,337	10,425	10,185	10,073	10,178
Industrial	894	822	908	916	904
Other	87	86	86	88	89
Total	107,525	107,321	106,855	106,335	106,385
Millions of kilowatt-hours sales					
Residential	726	688	666	701	733
Commercial	419	413	400	406	433
Industrial	1,003	969	912	906	946
Other	31	31	31	32	33
Subtotal	2,179	2,101	2,009	2,045	2,145
Wholesale	14	2	7	44	137
Total	2,193	2,103	2,016	2,089	2,282

ELECTRIC FACTS

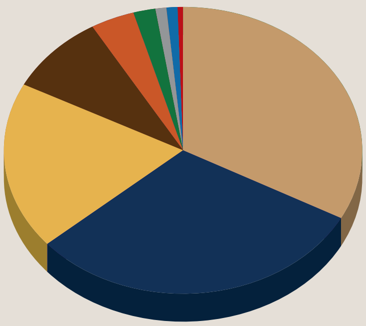
	2012/13	2011/12	2010/11	2009/10	2008/09
Average annual kWh per residential customer	7,547	7,208	7,006	7,397	7,739
Average price (cents/kWh) per residential customer	16.27	16.07	16.17	15.31	14.39
Debt service coverage ratio (DSC)[2]	2.73	2.24	2.21	2.75	2.58
Operating income as a percent of operating revenues	24.0%	22.1%	18.9%	23.5%	22.2%
Employees[1]	460	453	449	427	416

[1] Approved positions

[2] For FY 10/11 and thereafter, interest expense used to calculate DSC is net of federal subsidy on Build America Bonds.

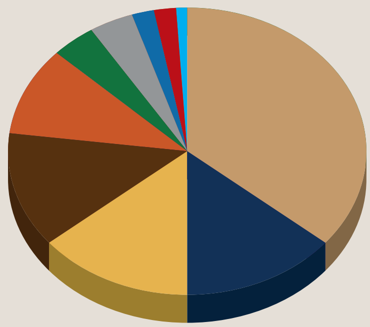
2012/2013 ELECTRIC REVENUE AND RESOURCES

Source of Revenue



- Residential Sales 33¢
- Industrial Sales 31¢
- Commercial Sales 19¢
- Transmission Revenue 9¢
- Other Revenue 4¢
- Public Benefit Programs 2¢
- Other Sales 1¢
- Investment Income 1¢
- Wholesale Sales < 1¢

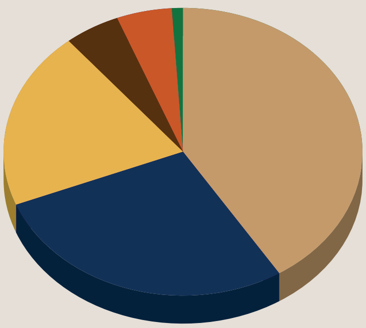
Distribution of Revenue



- Production 36¢
- Distribution 14¢
- Debt Service 14¢
- Transmission 13¢
- Transfers to the City's General Fund* 10¢
- Additional Reserves 4¢
- Regulatory Assets 4¢
- Public Benefit Programs 2¢
- Additions and Replacements to the System 2¢
- Extraordinary Item 1¢

** Based on transfer of 11.5% of fiscal year 2011/2012 operating revenues (excludes wholesale sales and Public Benefit Programs revenues).*

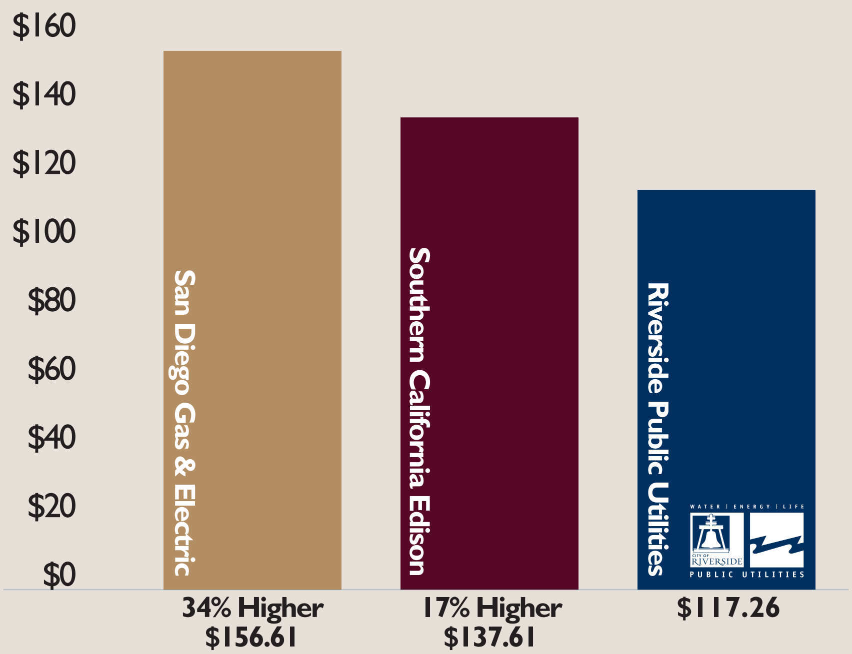
Energy Resources



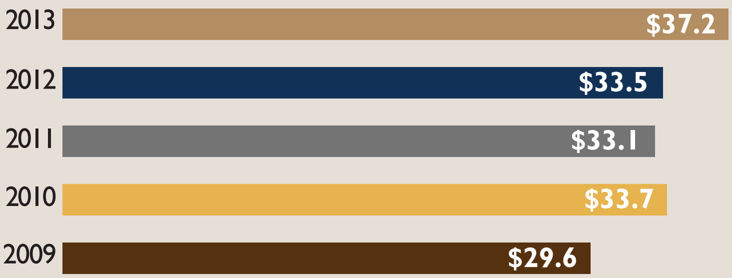
- Other Purchases 41%
- Coal 28%
- Renewables 20%
- Gas 5%
- Nuclear 5%
- Hydropower 1%

** Energy Resources are based on calendar year 2012 as filed with the California Energy Commission.*

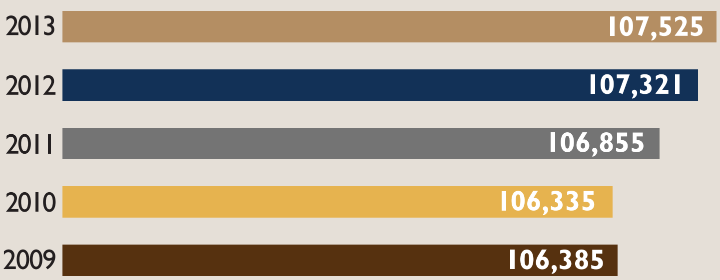
ELECTRIC RATE COMPARISON 750 KWH PER MONTH (AS OF JUNE 30, 2013)



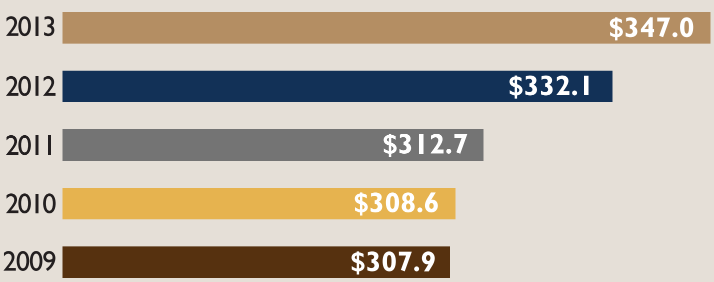
GENERAL FUND TRANSFER (IN MILLIONS)



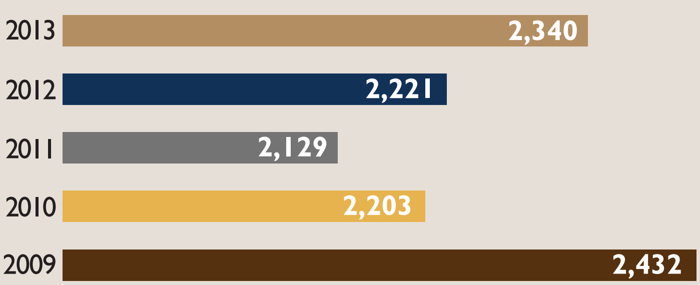
NUMBER OF METERS AT YEAR END



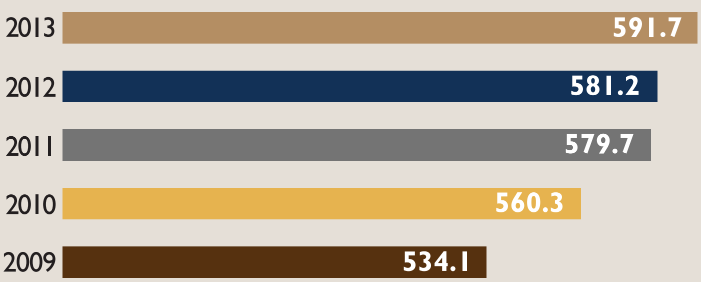
TOTAL OPERATING REVENUE (IN MILLIONS)



PRODUCTION (IN MILLION KILOWATT-HOURS)



PEAK DAY DEMAND (IN MEGAWATTS)



ELECTRIC FACTS AND SYSTEM DATA

Established	1895
Service Area Population	311,896
Service Area Size (square miles)	81.5
System Data:	
Transmission lines (circuit miles)	91.1
Distribution lines (circuit miles)	1,323
Number of substations	14
2012-2013 Peak day (megawatts):	592
Highest single hourly use:	
08/13/2012, 5 pm, 97 degrees	
Historical peak (megawatts):	604
08/31/2007, 4 pm, 106 degrees	

Bond Ratings

Fitch Ratings	AA-
Standard & Poor's	AA-
Debt Derivative Profile Score on Swap Portfolio	2

(1 representing the lowest risk and 4 representing the highest risk)