FINANCIAL STATEMENTS: ELECTRIC

RiversidePublicUtilities.com

BALANCE SHEETS

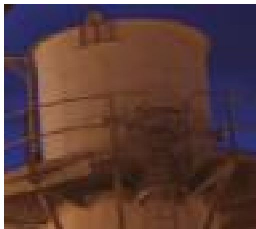
ASSETS	June 30, 2012	June 30, 2011
	(in thousands)	
UTILITY PLANT:		
Utility plant, net of depreciation (Note 3)	$ 703,435	$ 681,934
RESTRICTED ASSETS:		
Cash and cash equivalents (Note 2)	19,808	22,237
Cash and investments at fiscal agent (Note 2)	238,254	270,273
Total restricted non-current assets	258,062	292,510
OTHER NON-CURRENT ASSETS:		
Advances to City	5,558	5,558
Deferred pension costs (Note 1)	12,380	12,736
Deferred bond issuance costs	6,456	7,128
Deferred debits (Note 4)	30,922	10,016
Total other non-current assets	55,316	35,438
Total non-current assets	1,016,813	1,009,882
CURRENT ASSETS:		
Unrestricted assets:		
Cash and cash equivalents (Note 2)	187,541	168,905
Accounts receivable, less allowance for doubtful accounts 2012 $1,154; 2011 $1,161	38,559	35,524
Advances to City	2,277	4,195
Accrued interest receivable	825	1,381
Prepaid expenses	17,358	12,660
Nuclear materials inventory	1,992	1,905
Total unrestricted current assets	248,552	224,570
Restricted assets:		
Public Benefit Programs - Cash and cash equivalents (Note 2)	4,221	3,882
Public Benefit Programs receivable	834	697
Total restricted current assets	5,055	4,579
Total current assets	253,607	229,149
Total assets	$ 1,270,420	$ 1,239,031

See accompanying notes to the financial statements

BALANCE SHEETS

EQUITY AND LIABILITIES	June 30, 2012	June 30, 2011
	(in thousands)	
EQUITY:		
Invested in capital assets, net of related debt	$ 236,789	$ 224,953
Restricted for:		
Debt service (Note 5)	19,808	22,237
Public Benefit Programs	4,020	3,771
Unrestricted	219,198	199,159
Total equity	479,815	450,120
LONG-TERM OBLIGATIONS, LESS CURRENT PORTION (NOTE 4)	572,382	594,714
OTHER NON-CURRENT LIABILITIES:		
Advance from City - pension obligation (Notes 1 and 4)	12,003	12,381
Nuclear decommissioning liability (Notes 1 and 4)	71,709	67,969
Postemployment benefits payable (Notes 1 and 4)	3,809	2,775
Derivative instruments (Note 4)	38,123	17,216
Loan Payable (Note 4)	42,660	44,141
Capital leases payable (Notes 1 and 4)	901	1,303
Total non-current liabilities	169,205	145,785
CURRENT LIABILITIES PAYABLE FROM RESTRICTED ASSETS:		
Accrued interest payable	6,100	6,382
Public Benefit Programs payable	1,035	808
Current portion of long-term obligations (Note 4)	18,050	20,940
Total current liabilities payable from restricted assets	25,185	28,130
CURRENT LIABILITIES:		
Accounts payable and other accruals	19,204	15,821
Customer deposits	3,148	3,033
Loan Payable (Note 4)	1,481	1,428
Total current liabilities	23,833	20,282
Total liabilities	790,605	788,911
COMMITMENTS AND CONTINGENCIES (Notes 8 and 9)	-	-
Total equity and liabilities	$ 1,270,420	$ 1,239,031

See accompanying notes to the financial statements



STATEMENTS OF REVENUES, EXPENSES AND CHANGES IN EQUITY

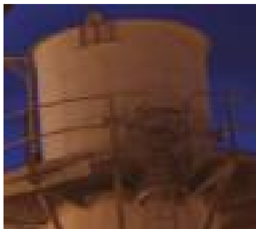
	For the Fiscal Years Ended June 30, 2012	2011
	(in thousands)	
OPERATING REVENUES:		
Residential sales	$ 110,471	$ 107,792
Commercial sales	66,047	64,039
Industrial sales	107,455	102,067
Other sales	5,614	5,529
Wholesale sales	50	124
Transmission revenue	30,735	22,091
Other operating revenue	4,018	4,015
Public Benefit Programs	8,639	8,046
Total operating revenues before (reserve)/recovery	333,029	313,703
Reserve for uncollectible, net of bad debt recovery	(971)	(1,021)
Total operating revenues, net of (reserve)/recovery	332,058	312,682
OPERATING EXPENSES:		
Production and purchased power	129,215	128,962
Transmission	45,447	40,434
Distribution	48,167	44,931
Public Benefit Programs	8,390	11,664
Depreciation	27,482	27,690
Total operating expenses	258,701	253,681
Operating income	73,357	59,001
NON-OPERATING REVENUES (EXPENSES):		
Investment income	6,196	10,368
Interest expense and fiscal charges	(29,127)	(21,220)
Gain on retirement of utility plant	487	5,931
Other	3,058	2,117
Total non-operating revenues (expenses)	(19,386)	(2,804)
Income before capital contributions and transfers	53,971	56,197
Capital contributions	9,257	4,056
Transfers out - contributions to the City's general fund	(33,533)	(33,070)
Total capital contributions and transfers out	(24,276)	(29,014)
Income before special item	29,695	27,183
SPECIAL ITEM:		
Intra-entity property acquisition	-	(17,114)
Increase in equity	29,695	10,069
EQUITY, BEGINNING OF YEAR	450,120	440,051
EQUITY, END OF YEAR	$ 479,815	$ 450,120

See accompanying notes to the financial statements

STATEMENTS OF CASH FLOWS

	For the Fiscal Years Ended June 30, 2012	2011
	(in thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Cash received from customers and users	$ 329,608	$ 308,733
Cash paid to suppliers and employees	(226,323)	(223,124)
Other receipts	3,058	2,117
Net cash provided by operating activities	106,343	87,726
CASH FLOWS FROM NON-CAPITAL FINANCING ACTIVITIES:		
Transfers out - contributions to the City's general fund	(33,533)	(33,070)
Payment on Advance from City - Pension obligation	(378)	(324)
Intra-entity property acquisition	-	(17,114)
Advances to City	1,918	(3,545)
Net cash used by non-capital financing activities	(31,993)	(54,053)
CASH FLOWS FROM CAPITAL AND RELATED FINANCING ACTIVITIES:		
Purchase of utility plant	(41,752)	(50,331)
Purchase of nuclear fuel	(4,908)	(1,554)
Proceeds from the sale of utility plant	554	495
Proceeds from revenue bonds, including premium	-	140,857
Principal paid on long-term obligations	(26,611)	(23,086)
Interest paid on long-term obligations	(30,764)	(24,985)
Capital contributions	6,818	2,925
Bond issuance costs	-	(1,124)
Net cash (used) provided by capital and related financing activities	(96,663)	43,197
CASH FLOWS FROM INVESTING ACTIVITIES:		
Proceeds (purchase) of investment securities	(60)	273
Income from investments	6,840	9,975
Net cash provided by investing activities	6,780	10,248
Net (decrease) increase in cash and cash equivalents	(15,533)	87,118
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR **(including $198,600 and $110,095 at June 30, 2011 and June 30, 2010, respectively, reported in restricted accounts)**	367,505	280,387
CASH AND CASH EQUIVALENTS, END OF YEAR **(including $164,431 and $198,600 at June 30, 2012 and June 30, 2011, respectively, reported in restricted accounts)**	$ 351,972	$ 367,505
RECONCILIATION OF OPERATING INCOME TO NET CASH PROVIDED BY OPERATING ACTIVITIES:		
Operating income	$ 73,357	$ 59,001
Adjustments to reconcile operating income to net cash provided by operating activities:		
Depreciation	27,482	27,690
Amortization of deferred charges-pension costs	356	291
Amortization of nuclear fuel/purchased power	954	1,449
Decrease in allowance for uncollectible accounts	(7)	(843)
Increase in accounts receivable	(2,558)	(3,251)
Increase in prepaid expenses	(4,698)	(1,912)
Increase in nuclear materials inventory	(87)	(80)
Increase (decrease) in accounts payable and other accruals	3,370	(2,479)
Increase in postemployment benefits payable	1,034	771
Increase in Public Benefit Programs	227	410
Increase in customer deposits	115	145
Increase in decommissioning liability	3,740	4,417
Other receipts	3,058	2,117
Net cash provided by operating activities	$ 106,343	$ 87,726
SCHEDULE OF NON-CASH INVESTING, CAPITAL AND FINANCING ACTIVITIES:		
Capital contributions - capital assets	1,832	1,131
Increase (decrease) in fair value of investments	136	(470)
Principal balance of revenue bonds refunded	-	56,450

See accompanying notes to the financial statements



NOTES TO THE FINANCIAL STATEMENTS: ELECTRIC

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The Electric Utility exists under, and by virtue of, the City of Riverside (the City) Charter enacted in 1883. The Electric 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 Electric Utility (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 Electric 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. 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. The Utility is not required to and does not elect to implement the pronouncements of the Financial Accounting Standards Board issued after November 1989.

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 Electric Utility customers are billed monthly. Unbilled electric service charges including the Public Benefit Programs, are recorded at year-end and are included in accounts receivable. Unbilled accounts receivable, totaled $13,496 at June 30, 2012, and $13,339 at June 30, 2011.

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 Electric 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	5 years

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

NUCLEAR FUEL

The Electric 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 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 (see Note 7).

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 on the Balance Sheets because their use is limited by applicable bond covenants. Funds set aside for the nuclear decommissioning reserve are also classified as restricted assets because their use is legally restricted to a specific purpose.

In January 1998, the Electric 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 Balance Sheets, Statements of Revenues, Expenses and Changes in Equity, and Statements of Cash Flows.

CASH AND INVESTMENTS

In accordance with the Electric 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 Governmental Accounting Standards Board (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 Statement of Net Assets/Balance Sheets 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, 2012, 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 Electric Utility and are pledged as collateral for payment of principal and interest on outstanding bonds, funds set aside to decommission the Utility's proportionate share of Units 2 and 3 at SONGS, or for use on construction of capital assets.

INTERNALLY RESTRICTED CASH RESERVES

Effective July 1, 2003, the City Council approved a Regulatory Risk Reserve Account of $4,000, an Energy Risk Management Reserve Account of $11,000, and an Operating Reserve Account of $14,000, all of which are considered internally restricted assets. The balance as of June 30, 2012 and 2011 respectively are as follows: Regulatory Risk Reserve $15,000 and $15,000, Energy Risk Management Reserve $30,000 and $30,000 and Operating Reserve $108,031 and $95,031, for a combined total of $153,031 and $140,031 and are included as a component of cash and cash equivalents in the accompanying Balance Sheets.

ADVANCES

Advances have been recorded as a result of agreements between the Electric Utility and the City. The balance as of June 30, 2012 and 2011 was $7,835 and $9,753, respectively.

DERIVATIVES

On July 1, 2009, the Electric Utility adopted 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 deferrals on the Balance Sheets. 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 Equity.

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 Balance Sheet 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 and normal sales" and are exempt from GASB 53.

BOND PREMIUMS, ISSUANCE COSTS, GAINS AND LOSSES ON REFUNDING

Bond premiums, issuance costs, and gains and losses on refunding (including gains and losses related to interest rate swap transactions) are deferred and amortized over the life of the bonds using the effective interest method. Bonds payable are reported net of the applicable bond premiums and gain or loss on refunding, whereas issuance costs are recorded as other assets.

NUCLEAR DECOMMISSIONING LIABILITY

Federal regulations require the Electric Utility to provide for the future decommissioning of its ownership share of the nuclear units at San Onofre. The Utility has established a trust account to accumulate resources for the decommissioning of the nuclear power plant and restoration of the beachfront at San Onofre. Based on the most recent site specific cost estimate as of February 2009 prepared by ABZ Incorporated, the Utility plans to set aside approximately $1,600 per year to fund this obligation. The funding will occur over the useful life of the generating plant or until the account is fully funded.

Increases to the trusts are from amounts set aside and investment earnings. The investment earnings are included in investment income in the Utility's financial statements. These amounts, as well as amounts set aside, are contributed to the trusts and reflected as decommissioning expense, which are considered part of power supply costs. The total amounts held in the trust accounts are classified as restricted assets and other non-current liability in the accompanying Balance Sheets. To date, the Utility has set aside $71,709 in cash investments with the trustee as the Utility's estimated share of the decommissioning cost of San Onofre. The plant site easement at San Onofre 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 Electric Utility has entered into eight capital lease agreements as a lessee for financing eight compressed natural gas heavy duty service trucks. These leases have seven year terms with monthly payments with interest rates ranging from 3.24% to 5.87%. The total gross value of the leases is $2,728 with depreciation over the seven year terms of the leases using the straight-line method.

For fiscal year ended June 30, 2012 and 2011, the total liability was $1,303 and $1,692, respectively, with the current portion included in accounts payable and other accruals. The minimum annual lease payments for the life of the leases are $442 annually through fiscal year ended June 30, 2014, $429 in the fiscal year ended June 30, 2015, and $65 in the fiscal year ended June 30, 2016. Total outstanding lease payments are $1,377, with $1,303 representing the present value of the net minimum lease payments and $74 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 Electric Utility's portion of these deposits as of June 30, 2012 and 2011 was $3,148 and $3,033, respectively.

COMPENSATED ABSENCES

The accompanying financial statements include accruals for salaries, fringe benefits and compensated absences due to employees at June 30, 2012 and 2011. The Electric Utility including the Public Benefit Programs, treats compensated absences due to employees as an expense and a current liability and is included in accounts payable and other accruals in the accompanying Balance Sheets. The amount accrued for compensated absences was $4,294 at June 30, 2012, and $4,275 at June 30, 2011.

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 Electric 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, 2012, may be found in the notes to the City's "Comprehensive Annual Financial Report."

Although the ultimate amount of losses incurred through June 30, 2012 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 Electric Utility including the Public Benefit Programs, were $737 and $713 for the years ended June 30, 2012 and 2011, 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), a public employee retirement system that services more than 3,000 public agency employers within the State of California and acts as a common investment and administrative agency for those participating public entities.

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. Employees may retire at age 55 and receive 2.7 percent of their highest annual salary for each year of service completed. For new employees hired after December 9, 2011, all bargaining units including management, SEIU, and IBEW, agreed to change the calculation from utilizing the highest year of salary to the average of the highest three years of salary. PERS also provides death and disability benefits. These benefit provisions and all other requirements are established by state statute and City ordinance.

Employee contributions are 8.0 percent of their annual covered salary. The Utility pays both the employee and employer contributions except for new employees hired after October 19, 2011, who pay their own 8.0 percent contribution. The Electric 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 total Electric Utility's contribution to PERS including the Public Benefit Programs as of June 30, 2012 and 2011 was $8,754 and $7,063, respectively. The employer portion of the PERS funding as of June 30, 2012 and 2011 was 18.44 percent and 14.51 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, 2012 and recent trend information may be found in the notes to the City's "Comprehensive Annual Financial Report" for the fiscal year ended June 30, 2012.

PENSION OBLIGATION BONDS

In 2005, the City issued Pension Obligations Bonds in the amount of $60,000, of which the Electric Utility's, including the Public Benefit Programs, share is $13,690. The deferred charge relating to 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 Bond proceeds were deposited with PERS to fund the unfunded actuarial accrued liability for non-safety employees. The balance in deferred pension costs as of June 30, 2012 and 2011 was $12,380 and $12,736, respectively as reflected in the accompanying Balance Sheets as deferred pension costs and a corresponding long-term obligation. 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, 2012.

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

OTHER POSTEMPLOYMENT BENEFITS

The City contributes to two single-employer defined benefit healthcare plans: Stipend Plan (SP) and the Implied Subsidy Plan (ISP). The plans provide other postemployment health care benefits (OPEB) for eligible retirees and beneficiaries.

The Stipend Plan is available to eligible retirees and beneficiaries pursuant to their collective bargaining agreements. The Electric Utility currently contributes to two bargaining units through the International Brotherhood of Electrical Workers General Trust (IBEW) and Service Employee's International Union General Trust (SEIUG). Benefit provisions for the Stipend Plan for eligible retirees and beneficiaries are established and amended through the various memoranda of understanding (MOU). The MOU's are agreements established between the City and the respective employee associations. The City does not issue separate stand-alone financial reports for the plans, instead financial information for the trust funds can be obtained by contacting the individual association.

The Utility also provides benefits to retirees in the form of an implicit rate subsidy (Implied Subsidy). Under an implied rate subsidy, retirees and current 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 are receiving the benefit of a lower rate.

The contribution requirements of the Utility for the Stipend Plan are established and may be amended through the MOU between the City and the unions. The Utility's contribution is financed on a "pay-as-you-go-basis" and the current contribution is unfunded. The contribution requirements of the Utility's Implied Subsidy Plan are established by the City Council. The Utility 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) for each plan is calculated based on annual required contribution (ARC) of the employer, an amount actuarially determined in accordance with the parameters of GASB Statement No. 45, *Accounting and Financial Reporting by Employers for Postemployment Benefits Other Than Pensions* (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 liabilities (or funding excess) (UAAL) over a period not to exceed thirty years. The Electric Utility's OPEB liability including the Public Benefit Programs as of June 30, 2012 and 2011 was $3,869 and $2,834, respectively.

City-wide information concerning the description of the plans, funding policy and annual OPEB cost, funding status and funding progress, and actuarial methods and assumptions for the year ended June 30, 2012 can be found in the notes to the City's "Comprehensive Annual Financial Report" for the fiscal year ended June 30, 2012.

EQUITY

The Electric Utility's equity consists of its net assets (assets less liabilities) which are classified into the following three components:

Invested in capital assets, net of related debt – 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.

Restricted – this component consists of net assets 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 of net assets consists of net assets that do not meet the definition of "restricted" or "invested in capital assets, net of related debt."

CONTRIBUTIONS TO THE CITY'S GENERAL FUND

Pursuant to the City of Riverside Charter, the Electric 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, 2012 and 2011, $33,533 and $33,070, 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 Electric 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 Electric Utility's prior year financial statements, from which this selected financial data was derived.

NOTE 2. CASH AND INVESTMENTS

Cash and investments at June 30, 2012 and 2011, consist of the following (in thousands):

	June 30, 2012	June 30, 2011
	Fair Value	
Equity interest in City Treasurer's investment pool	$ 211,570	$ 195,024
Cash and investments at fiscal agent	238,254	270,273
Total cash and investments	$ 449,824	$ 465,297

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

	June 30, 2012	June 30, 2011
Unrestricted cash and cash equivalents	$ 187,541	$ 168,905
Restricted cash and cash equivalents	24,029	26,119
Restricted cash and investments at fiscal agent	238,254	270,273
Total cash and investments	$ 449,824	$ 465,297

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	$ 4,030	$ 4,030	$ -	$ -	$ -
Federal agency securities	48,436	3,420	3,643	41,373	-
Investment contracts [1]	162,604	-	147,813	4,030	10,761
Corp medium term notes	23,184	3,070	-	20,114	-
City Treasurer's investment pool [2]					
Money market funds	36,251	36,251	-	-	-
Federal agency securities	94,107	11,446	21,665	60,996	-
Corp medium term notes	29,029	4,915	10,077	14,037	-
State investment pool	48,358	48,358	-	-	-
Neg Certificate of Deposit	3,825	121	2,393	1,311	-
Total	$ 449,824	$ 111,611	$ 185,591	$ 141,861	$ 10,761

NOTE 2. CASH AND INVESTMENTS (CONTINUED)

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

Investment Type	Total	Rating as of Year End AAA	AA	A	Unrated
Held by fiscal agent					
Money market funds	$ 4,030	$ 3,991	$ -	$ -	$ 39
Federal agency securities	48,436	48,436	-	-	-
Investment contracts [1]	162,604	-	-	-	162,604
Corp medium term notes	23,184	-	17,552	5,632	-
City Treasurer's investment pool [2]					
Money market funds	36,251	881	20,988	14,382	-
Federal agency securities	94,107	94,107	-	-	-
Corp medium term notes	29,029	-	23,828	5,201	-
State investment pool	48,358	-	-	-	48,358
Negotiable Certificate of Deposit	3,825	-	-	-	3,825
Total	$ 449,824	$ 147,415	$ 62,368	$ 25,215	$ 214,826

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, 2012 and 2011 (in thousands):

	Balance As of 6/30/10	Additions	Retirements /Transfers	Balance As of 6/30/11	Additions	Retirements /Transfers	Balance As of 6/30/12
Production [1]	$ 274,392	$ 152,817	$ (634)	$ 426,575	$ 5,162	$ (82,473)	$ 349,264
Transmission	28,484	668	-	29,152	2,902	-	32,054
Distribution	440,297	25,196	(2,056)	463,437	32,142	(661)	494,918
General	55,857	1,726	(4,601)	52,982	1,172	(361)	53,793
Intangibles	-	-	-	-	292	-	292
Depreciable utility plant	799,030	180,407	(7,291)	972,146	41,670	(83,495)	930,321
Less accumulated depreciation:							
Production [1]	(147,832)	(11,741)	106	(159,467)	(11,316)	67,832	(102,951)
Transmission	(12,171)	(650)	-	(12,821)	(671)	-	(13,492)
Distribution	(150,450)	(11,972)	2,056	(160,366)	(12,577)	660	(172,283)
General	(20,763)	(3,327)	4,401	(19,689)	(2,913)	294	(22,308)
Intangibles					(5)	-	(5)
Accumulated depreciation	(331,216)	(27,690)	6,563	(352,343)	(27,482)	68,786	(311,039)
Net depreciable utility plant	467,814	152,717	(728)	619,803	14,188	(14,709)	619,282
Nuclear fuel, at amortized cost	4,773	1,554	(1,449)	4,878	4,907	(953)	8,832
Production [1]	-	-	-	-	-	14,641	14,641
Land	7,612	60	(27)	7,645	9	-	7,654
Intangibles, non-amortizable	-	9,821	-	9,821	-	-	9,821
Construction in progress	126,578	50,813	(137,604)	39,787	45,771	(42,353)	43,205
Nondepreciable utility plant	134,190	60,694	(137,631)	57,253	45,780	(27,712)	75,321
Total utility plant	$ 606,777	$ 214,965	$ (139,808)	$ 681,934	$ 64,875	$ (43,374)	$ 703,435

1 The San Onofre Generating Station (SONGS) Units 2 and 3 were taken offline in January 2012 and remain offline for extensive inspections, testing and analysis resulting from excessive wear of tubes in the steam generators (See Note 7 for further information on SONGS). It is anticipated that Unit 2 could restart months in advance of Unit 3. Due to the uncertainty of Unit 3 restart date, the capital assets of Unit 3 are reclassified from a depreciable to a non-depreciable utility plant asset until it is restored to service. Unit 2 will remain classified as a depreciable utility plant asset since it is anticipated that it could be restored to service in the coming months.

NOTE 4. LONG-TERM OBLIGATIONS

The following is a summary of changes in long-term obligations during the fiscal years ended June 30, 2012 and 2011 (in thousands):

	Balance As of 6/30/10	Additions	Reductions	Balance As of 6/30/11	Additions	Reductions	Balance As of 6/30/12	Due Within One Year
Revenue bonds	$ 501,879	$ 192,722	$ (79,048)	$ 615,553	$ -	$ (25,311)	$ 590,242	$ 18,050
Arbitrage liability	27	75	-	102	88	-	190	-
Advance from City - pension obligation	12,705	-	(324)	12,381	-	(378)	12,003	-
Postemployment benefits payable	2,004	771	-	2,775	1,034	-	3,809	-
Nuclear decommissioning liability	63,552	4,417	-	67,969	3,740	-	71,709	-
Capital leases	2,073	-	(381)	1,692	-	(389)	1,303	402
Loan Payable	-	45,569	-	45,569	-	(1,428)	44,141	1,481
Total long-term obligations	$ 582,240	$ 243,554	$ (79,753)	$ 746,041	$ 4,862	$ (27,506)	$ 723,397	$ 19,933

LOAN PAYABLE

The Electric 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 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 payments ranging from $181 to $1,480 from September 2012 through March 2014. 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.

NOTE 4. LONG-TERM OBLIGATIONS (CONTINUED)

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

REVENUE BONDS PAYABLE

	June 30, 2012	June 30, 2011
$47,215 2001 Electric Revenue Bonds: all outstanding bonds were called 10/1/2011	$ -	$ 7,525
$75,405 2003 Electric Refunding/Revenue Bonds: serial bonds due in annual installments from $6,880 to $8,535 through October 1, 2013, interest from 4.3 percent to 5.0 percent	15,415	23,665
$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 percent to 5.5 percent	9,845	13,125
$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 27, 2012 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 27, 2012 was 3.2 percent)	55,125	56,450
$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 percent to 5.0 percent	24,335	27,425
$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 percent 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 percent 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 27, 2012 was 3.1 percent)	55,125	56,450
Total electric revenue bonds payable	594,480	619,275
Unamortized deferred bond refunding costs	(12,877)	(13,813)
Unamortized bond premium	8,639	10,091
Total electric revenue bonds payable, net of deferred bond refunding costs and bond premium	590,242	615,553
Less current portion of revenue bonds payable	(18,050)	(20,940)
Total long-term electric revenue bonds payable	$ 572,192	$ 594,613

Revenue bonds annual debt service requirements to maturity as of June 30, 2012, are as follows (in thousands):

	2013	2014	2015	2016	2017	2018-22	2023-27	2028-32	2033-37	2038-41	Total
Principal	$ 18,050	$ 20,685	$ 14,480	$ 15,415	$ 12,745	$ 70,800	$ 84,895	$ 103,885	$ 127,900	$ 125,625	$ 594,480
Interest	25,455	24,543	23,745	23,113	22,620	105,832	91,074	71,403	46,144	12,824	446,753
Total	$ 43,505	$ 45,228	$ 38,225	$ 38,528	$ 35,365	$ 176,632	$ 175,969	$ 175,288	$ 174,044	$ 138,449	$ 1,041,233

The Electric 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 Electric Utility's debt service coverage ratio was 2.24 and 2.21 at June 30, 2012 and 2011, respectively. This debt (revenue bonds) is backed by the revenues of the Utility.

PRIOR YEAR DEFEASANCE OF DEBT

In prior years, the Electric Utility defeased certain Revenue Bonds by placing the proceeds of the new bonds in an irrevocable trust to provide for all future debt service payments on the old bonds. Accordingly, the trust account assets and the liability for the defeased bonds are not included in the Utility's financials statements. At fiscal year ended June 30, 2012, no bonds outstanding were considered defeased.

2010 ELECTRIC REVENUE BONDS

On December 16, 2010, the Electric Utility issued $133,290 of Electric Revenue Series A Bonds (federally taxable, Build America Bonds) to finance certain Electric System Improvements as outlined in the 5-year Capital Improvement Program, including system reliability projects such as a 230-69 kV transmission substation and upgrades to the Utility's generation stations. Annual principal payments ranging from $2,300 to $33,725 are due from October 1, 2020 through October 1, 2040, with associated interest rates of 3.91% to 4.94%.

On December 16, 2010, the Utility also issued $7,090 of Electric Revenue Series B Bonds to finance certain Electric System Improvements as outlined in the 5-year Capital Improvement Program. Annual principal payments ranging from $95 to $2,440 are due from October 1, 2016 through October 1, 2019, with associated interest rates of 3.00% to 5.00%.

2011 ELECTRIC REFUNDING/REVENUE BONDS

In April 2008, the Electric Utility refinanced $199,115 of Auction Rate Securities (ARS) with Variable Rate Demand Notes (VRDNs). The VRDNs require credit enhancements (e.g. insurance or a bank letter of credit) to ensure the debt service payments to bondholders are made should the Utility fail to make payment. Bank of America/Merrill Lynch (BAML) provided the Letter of Credit (LOC) at attractive rates. The LOC with BAML expired in April 2011. Renewing the existing LOC with BAML would result in higher rates due to a limited number of highly-rated banks offering this service. To mitigate various risk exposure and to provide an overall lower cost of financing, the Utility restructured one of three 2008 VRDNs by refunding the 2008 VRDNs with the 2011 VRDNs.

On April 28, 2011, $56,450 of Electric Refunding/Revenue Series A Bonds were sold with an all-in true interest cost of 3.89% to refund $56,450 of previously outstanding 2008 Electric Refunding/Revenue Series B Bonds. The refunding resulted in a difference between the reacquisition price and the net carrying amount of the old debt of $193. The difference is being charged to operations using the proportional method. Principal payments are due on October 1, 2011 until the maturity date of October 1, 2035 ranging from $725 to $5,175.

INTEREST RATE SWAPS ON REVENUE BONDS

The Electric 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 in the net carrying amount of 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.

NOTE 4. LONG-TERM OBLIGATIONS (CONTINUED)

A summary of the derivative activity for the year ended June 30, 2012 is as follows:

	Notional Amount	Fair Value as of 6/30/2012	Change in Fair Value for Fiscal Year
2008 Electric Refunding/Revenue Bonds Series A	$ 84,515	$ (14,985)	$ (7,957)
2008 Electric Refunding/Revenue Bonds Series C	$ 57,325	$ (11,584)	$ (6,476)
2011 Electric Refunding/Revenue Bonds Series A	$ 56,450	$ (11,554)	$ (6,474)

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 year 2036.

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, 2012, rates were as follows:

Interest rate swap:	Terms	2008 Electric Refunding/Revenue Series A Bonds Rates	2008 Electric Refunding/Revenue Series C Bonds Rates	2011 Electric Refunding/Revenue Series A Bonds Rates
Fixed payment to counterparty	Fixed	3.11100%	3.20400%	3.20100%
Variable payment from counterparty	62.68 LIBOR + 12bps	(0.51321%)	(0.51505%)	(0.26627%)
Net interest rate swap payments		2.59779%	2.68895%	2.93473%
Variable-rate bond coupon payments		0.47253%	0.46955%	0.13270%
Synthetic interest on bonds		3.07032%	3.15850%	3.06743%

Fair value: As of June 30, 2012, in connection with all swap agreements, the transactions had a total negative fair value of ($38,123). 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, 2012, 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, 2012, there is no requirement for collateral posting for any of the outstanding swaps.

Basis risk: As noted above, the swaps expose the Utility to basis risk should the relationship between LIBOR and the variable interest rate 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, 2012, 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
2013	$ 2,750	$ 723	$ 5,218	$ 8,691
2014	2,850	715	5,138	8,703
2015	4,800	697	5,006	10,503
2016	12,275	654	4,669	17,598
2017	11,500	612	4,355	16,467
2018-2022	38,375	2,618	18,908	59,901
2023-2027	38,760	1,777	13,483	54,020
2028-2032	44,105	902	8,001	53,008
2033-2036	39,350	183	1,709	41,242
Total	$ 194,765	$ 8,881	$ 66,487	$ 270,133

NOTE 5. RESTRICTED EQUITY

Pursuant to applicable bond indentures, a reserve for debt service has been established by restricting assets and reserving a portion of equity. 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 of Riverside 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 cities of Cerritos and San Marcos were admitted as members of SCPPA. In August 2003, the Authority rescinded the membership of the City of San Marcos, as the City no longer met the criteria for membership. 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 2011-12 and 2010-11 fiscal years, the Electric Utility paid approximately $20,855 and $18,725, 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.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NOTE 6. JOINTLY-GOVERNED ORGANIZATIONS (CONTINUED)

POWER AGENCY OF CALIFORNIA

On July 1, 1990, the City of Riverside 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. The Agency can only be reactivated by authorization of the Agency Board.

NOTE 7. JOINTLY-OWNED UTILITY PROJECT – SONGS

Pursuant to a settlement agreement with Southern California Edison (SCE), dated August 4, 1972, the Electric Utility was granted the right to acquire a 1.79 percent ownership interest in the San Onofre Nuclear Generating Station (SONGS) Units 2 and 3, equating to 19.2 MW and 19.3 MW respectively, of the available capacity. In the settlement agreement, SCE agreed to provide the necessary transmission service to deliver the output of SONGS to Riverside. SCE and the Utility entered into the SONGS Participation Agreement that sets forth the terms and conditions under which the Utility participates in the ownership and output of SONGS. Other participants in this project include SCE, 75.05 percent; San Diego Gas & Electric Company, 20.00 percent; and the City of Anaheim, 3.16 percent. In 2006, Anaheim sought and received approval to transfer its 3.16 percent to SCE for a total of 78.21 percent ownership. The Amended and Restated Operating Agreement was updated to reflect the change in ownership. Maintenance and operation of SONGS remain the responsibility of SCE, as operating agent for the Utility.

The original operating license for SONGS Units 2 and 3 was set to expire in 2013; however, this was subsequently extended due to a construction recapture provision, and now expires February 16, 2022 and November 15, 2022 for Units 2 and 3 respectively. It has been reported that SCE is pursuing a license extension from the Nuclear Regulatory Commission (NRC) to continue operations through 2042. To date, there is no final ruling on this extension request.

There are no separate financial statements for the jointly-owned utility plant since each participant's interests in the utility plant and operating expenses are included in their respective financial statements. The Electric Utility's 1.79 percent share of the capitalized construction costs for SONGS totaled $164,945 and $159,907 and accumulated depreciation totaled $135,664 and $133,260 for fiscal years ended June 30, 2012 and 2011, respectively. Capital assets are depreciated through 2022, to include the construction recapture extension period. The Utility sets aside approximately $1,600 per year to fund decommissioning costs (see Note 1). The Utility's portion of current and long-term debt associated with SONGS is included in the accompanying financial statements.

RECENT DEVELOPMENTS

In fiscal years 2010 and 2011, SCE completed the replacement of four steam generators at SONGS Units 2 and 3. The total cost of the project was $758,000 of which approximately $13,600 represented the Utility's share. On January 31, 2012, a water leak was detected in one of the heat transfer tubes in Unit 3 steam generators which required Unit 3 to be taken offline. During this same timeframe, Unit 2 was offline for a planned maintenance and refueling outage. During inspections of Unit 2 in February 2012, similar unexpected wear was observed in some Unit 2 heat transfer tubes albeit much less extensive than Unit 3 tube wear. Both Units 2 and 3 remain offline for extensive inspections, testing and analysis of the steam generators.

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

In March 2012, the NRC issued a Confirmatory Action Letter that required NRC permission to restart Units 2 and 3 and further outlined actions that SCE must complete before permission to restart either Unit may be considered. SCE is continuing to evaluate repairs and mitigation plans. Each Unit will be restarted only when the repairs and appropriate mitigation plans are completed in accordance with the NRC's letter and SCE is satisfied that it is safe to do so.

On August 3, 2012, SCE declared an "operating impairment", as defined in the Operating Agreement, for SONGS Units 2 and 3 and provided formal notification to the co-owners that the impairment resulted from excessive wear of the tubes in the steam generators. To date, SCE does not have a cost estimate and schedule for completing Restoration Work that will return both Units to service. SCE understands that the tube-to-tube contact arose from excessive vibration of the tubes in certain areas of the steam generators. Because Unit 2 experienced considerably less tube-to-tube wear, it is currently anticipated that Unit 2 could restart months in advance of Unit 3 and would only be able to operate at reduced power levels and with mid-cycle outages to provide assurance of safe operation. As a result, as shown in Note 3, the capital assets of Unit 3 are reclassified from a depreciable to a non-depreciable utility plant asset until it is restored to service.

On October 4, 2012, SCE submitted its response to the NRC Confirmatory Action Letter, along with its restart plan for SONGS Unit 2. The response and restart plans are being submitted simultaneously to provide the NRC with all the relevant information needed to evaluate the full spectrum of repairs, corrective actions and additional safety measures proposed to restart safe operations at the plant. SONGS Unit 3 will remain offline while the utility continues to study the potential solutions that are unique to this unit. The unit cannot be restarted until all plans have been approved by the NRC.

Due to the Fukushima nuclear power plant crisis in Japan in March 2011, NRC has instituted a comprehensive review of disaster preparedness of all nuclear power plants currently in operation in the U.S. SONGS has participated and is continuing to participate in this comprehensive disaster preparedness assessment effort. The ultimate outcome of this assessment is currently undetermined.

NOTE 8. COMMITMENTS

TAKE-OR-PAY CONTRACTS

The Electric 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 the remaining projects have fixed interest rates which range from 1.25 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
2013	$ 17,514	$ 672	$ 8,191	$ 717	$ 318	$ 3,090	$ 30,502
2014	22,693	676	8,213	719	274	3,117	35,692
2015	21,114	680	8,242	718	265	3,004	34,023
2016	23,975	683	8,093	718	257	2,901	36,627
2017	14,046	687	8,001	717	258	2,905	26,614
2018-2022	93,494	-	40,607	-	772	8,719	143,592
2023-2027	10,883	-	22,568	-	-	-	33,451
Total	$ 203,719	$ 3,398	$ 103,915	$ 3,589	$ 2,144	$ 23,736	$ 340,501

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, 2012 and 2011, 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
2012	$ 22,555	$ 2,843	$ 2,677	$ 102	$ 40	$ 300	$ 28,517
2011	$ 29,530	$ 2,792	$ 2,460	$ 100	$ 43	$ 298	$ 35,223

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

The Utility has become a Participating Transmission Owner (PTO) with the 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.

NOTE 8. COMMITMENTS (CONTINUED)

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 (the "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 (H.R. 470 Legislation) 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 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 Electric Utility has executed two firm power purchase agreements with Bonneville Power Administration (BPA). The first agreement with BPA was for the purchase of firm capacity (23 megawatts in the summer months and 16 megawatts in the winter months) beginning February 1, 1991, for a period of 20 years. This agreement terminated on March 3, 2011. The second BPA agreement is for the purchase of capacity (50 megawatts during the summer months and 13 megawatts during the winter months) beginning April 30, 1996, for 20 years. Effective May 1, 1998, these summer and winter capacity amounts increased to 60 megawatts and 15 megawatts, respectively, for the remainder of the second agreement.

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. The Act limits liability from third-party claims to approximately $12.6 billion per incident. Under the industry wide retrospective assessment program provided for under the Act, assessments are limited to $117.5 million per reactor for each nuclear incident occurring at any nuclear reactor in the United States, with payments under the program limited to $17.5 million per reactor, per year, per event to be indexed for inflation every five years. The next inflation adjustment will occur no later than October 29, 2013. Based on the Electric Utility's interest in Palo Verde and ownership in SONGS, the Utility would be responsible for a maximum assessment of $5,331, limited to payments of $794 per incident, per year. If the public liability limit above is insufficient, federal regulations may impose further revenueraising 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 (SB 2 (1X)) was passed by the State Legislative and signed by the Governor. SB 2 (1X) 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 SB 2 (1X) on November 18, 2011 and December 13, 2011, respectively. The Utility met SB 2 (1X) Stage 1 requirement for 2011 which requires an average of 20% of retail sales come from renewable resources. The Utility does not anticipate it will have difficulty meeting the remaining requirements of SB 2 (1X).

The contracts in the following table were executed as part of compliance with this standard. The Electric Utility also has an agreement with Bonneville Power Administration for the purchase of energy credits that add to the total renewable portfolio.

Long-term renewable power purchase agreements (in thousands):

Supplier	Type	Maximum Contract	Contract Expiration	Estimated Annual Cost For 2013
Salton Sea Power LLC	Geothermal	46.0 MW	5/31/2020	$ 21,176
Wintec	Wind	1.3 MW	12/30/2018	205
Total		47.3 MW		$ 21,381

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.

On August 23, 2005, the City Council approved an amendment to the Purchase Power Agreement ("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, at the same price under the current contract until 2013, with escalation thereafter based on an inflationary type index. Similar to other renewable power purchase agreements, 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 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 Energy, Ltd entered into an Assignment Agreement with WKN Wagner, LLC 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 is currently in negotiations with WKN on a Power Purchase Agreement.

CONSTRUCTION COMMITMENTS

As of June 30, 2012, the Electric Utility had major commitments (encumbrances) of approximately $13,343 with respect to unfinished capital projects, of which $12,623 is expected to be funded by bonds and $720 funded by rates.

FORWARD PURCHASE/SALE AGREEMENTS

In order to meet summer peaking requirements, the Electric 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, 2012, the Electric Utility has net commitments for fiscal year 2013 and thereafter, of approximately $24,079, with a market value of $20,435.

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 operations of the Utility.

NOTE 9. LITIGATION (CONTINUED)

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 Electric 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 Electric 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 $29,414,941, an increase of $3,900,000 from the previous TRR of $25,514,941. The new TRR became effective August 1, 2011.

NOTE 10. SPECIAL ITEM

On January 4, 2011, City Council approved the purchase of the 56-acre AB Brown Sports Complex property from the Water Utility to the Electric Utility for a fair market value of $11,600. The purchase was facilitated to balance the short and long-term investment and reserve assets of the Electric and Water Utility. The purchase will allow future appreciation of the property to accrue to the Electric Utility and will increase the financial liquidity of the Water Utility, both in efforts to maintain high credit ratings and to improve the overall financial position of both utilities.

The original and carrying value of the land in the Electric Utility was $17. The balance between the purchase price and carrying value of $11,583 was recorded as a special item.

On March 1, 2011, City Council approved the purchase of certain property (Reid Park land and a 64 acre portion of the former Riverside Golf Course) from the Water Utility to the Electric Utility for a fair market value of $720 and $4,838 for the park and the golf course, respectively, for a combined total of $5,558 with a subsequent sale from the Electric Utility to the City's former Redevelopment Agency. The land was originally purchased by the Water Utility in the 1930's to acquire water rights and expand certain well locations and is in excess to the current and long-term needs of the water system. The City intends that portions of the property (including the park) will remain public facilities and will be further developed for recreational purposes to benefit the community with another portion to be used for redevelopment purposes. The sale to the City's former Redevelopment Agency is secured by a 20-year promissory note.

The original and carrying value of the property was $27. The balance between the purchase price and carrying value was $5,531 and was recorded as a special item.

KEY HISTORICAL OPERATING DATA: ELECTRIC

KEY HISTORICAL OPERATING DATA

POWER SUPPLY (MWH)

	2011/12	2010/11	2009/10	2008/09	2007/08
Nuclear					
San Onofre	191,900	284,900	240,000	281,400	286,500
Palo Verde	101,100	102,000	96,300	97,700	85,200
Coal					
Intermountain Power	799,700	895,600	1,068,500	1,051,200	1,094,100
Deseret	0	0	187,400	406,000	427,600
Hoover (Hydro)	35,300	32,900	30,000	32,500	33,700
Gas					
Springs	2,300	3,100	1,400	3,300	2,300
RERC	39,400	34,500	11,500	48,700	46,800
Clearwater	17,000	9,700	0	0	0
Renewable Resources	409,800	385,700	354,900	233,000	247,800
Other purchases	682,500	464,200	276,500	349,200	594,100
Exchanges In	75,200	92,200	92,700	90,000	115,700
Exchanges Out	(133,500)	(176,100)	(156,200)	(160,600)	(202,600)
Total:	2,220,700	2,128,700	2,203,000	2,432,400	2,731,200
System peak (MW)	581.2	579.7	560.3	534.1	604.4

ELECTRIC USE

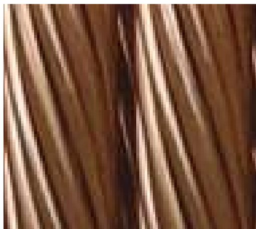
	2011/12	2010/11	2009/10	2008/09	2007/08
Number of meters as of year end					
Residential	95,988	95,676	95,258	95,214	94,691
Commercial	10,425	10,185	10,073	10,178	10,258
Industrial	822	908	916	904	978
Other	86	86	88	89	88
Total:	107,321	106,855	106,335	106,385	106,015
Millions of kilowatt-hours sales					
Residential	688	666	701	733	734
Commercial	413	400	406	433	441
Industrial	969	912	906	946	960
Other	31	31	32	33	34
Subtotal:	2,101	2,009	2,045	2,145	2,169
Wholesale	2	7	44	137	357
Total:	2,103	2,016	2,089	2,282	2,526

ELECTRIC FACTS

	2011/12	2010/11	2009/10	2008/09	2007/08
Average annual kWh per residential customer	7,208	7,006	7,397	7,739	7,779
Average price (cents/kWh) per residential customer	16.07	16.17	15.31	14.39	13.61
Debt service coverage ratio (DSC)[2]	2.24	2.21	2.75	2.58	2.62
Operating income as a percent of operating revenues	22.1%	18.9%	23.5%	22.2%	16.4%
Employees[1]	453	449	427	416	405

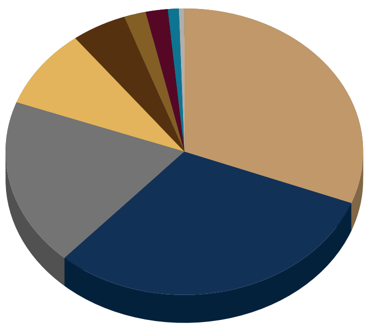
[1] Approved Positions

[2] For FY 11/12, interest expense used to calculate DSC is net of federal subsidy on Build America Bonds.



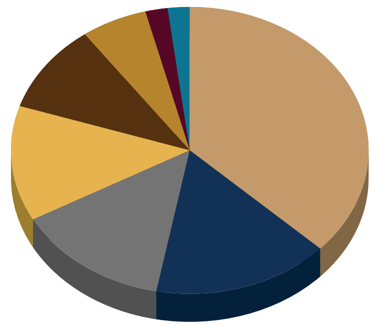
2011/2012 ELECTRIC REVENUE AND RESOURCES

Source of Revenue



- Residential Sales 31¢
- Industrial Sales 31¢
- Commercial Sales 19¢
- Transmission Revenue 9¢
- Other Revenue 5¢
- Investment Income 2¢
- Public Benefit Programs 2¢
- Other Sales 1¢
- Wholesale Sales (less than 1¢)

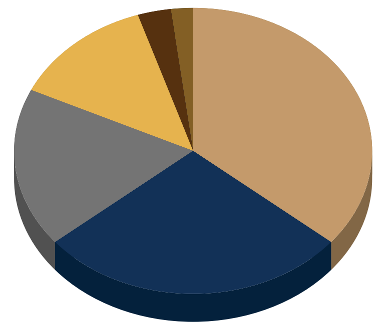
Distribution of Revenue



- Production 37¢
- Debt Service 16¢
- Distribution 14¢
- Transmission 13¢
- Transfers to the City's General Fund* 10¢
- Additional Reserves 6¢
- Public Benefit Programs 2¢
- Additions and Replacements to the System 2¢

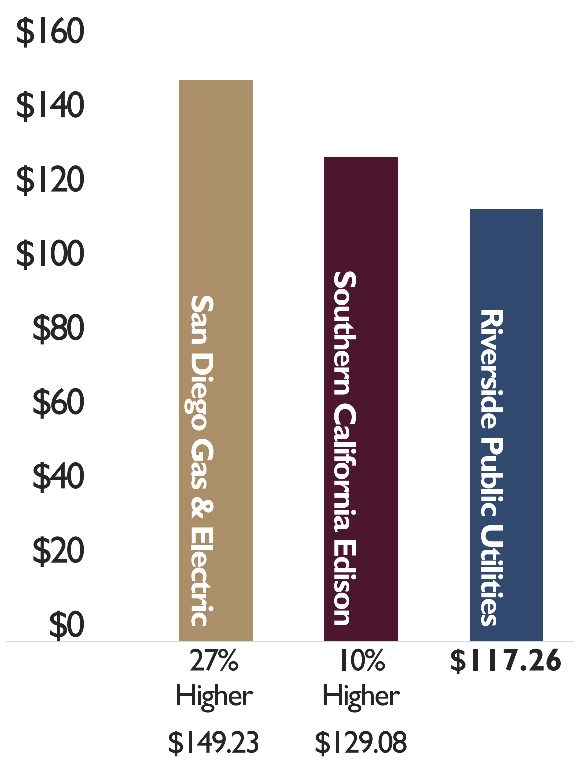
** Based on transfer of 11.5% of fiscal year 2010/2011 operating revenues (excludes wholesale sales and Public Benefit Programs revenues).*

Energy Resources

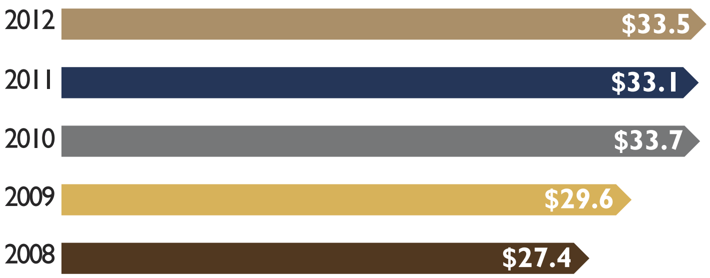


- Coal 36%
- Other Purchases 28%
- Renewables 18%
- Nuclear 13%
- Gas 3%
- Hydropower 2%

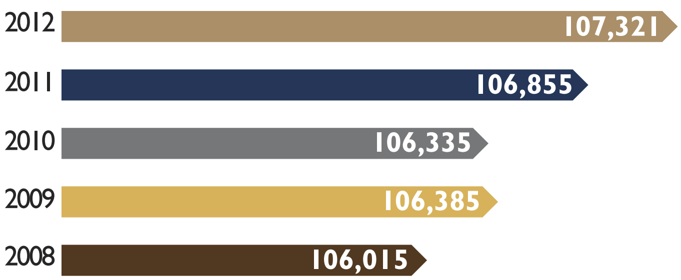
ELECTRIC RATE COMPARISON – 750 KWH PER MONTH (AS OF JUNE 30, 2012)



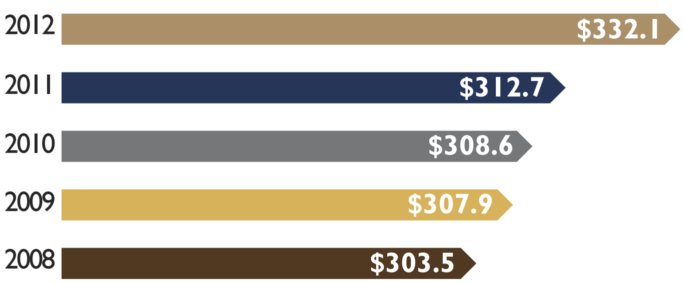
GENERAL FUND TRANSFER (IN MILLIONS)



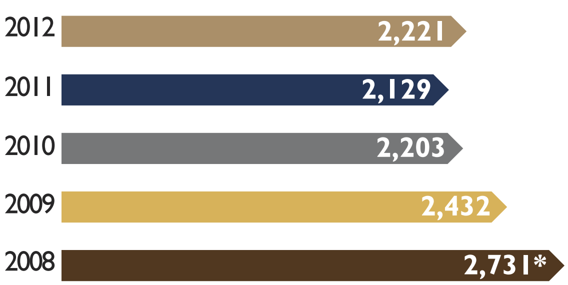
NUMBER OF METERS AT YEAR END



TOTAL OPERATING REVENUE (IN MILLIONS)



PRODUCTION (IN MILLION KILOWATT-HOURS)



** Energy shown before transmission losses net of exchanges*

PEAK DAY DEMAND (IN MEGAWATTS)

ELECTRIC FACTS AND SYSTEM DATA

Established	1895
Service Area Population	308,452
Service Area Size (square miles)	81.5
System Data:	
Transmission lines (circuit miles)	91.1
Distribution lines (circuit miles)	1,319
Number of substations	14
2011-2012 Peak day (megawatts):	581
Highest single hourly use:	
09/17/2011, 4 pm, 101 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)