Electric

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To the Honorable City Council and Board of Public Utilities
City of Riverside
Riverside, California

INDEPENDENT AUDITORS' REPORT

We have audited the accompanying financial statements of the City of Riverside, California, Electric Utility, an enterprise fund of the City, as of and for the year ended June 30, 2010 as listed in the table of contents. These financial statements are the responsibility of the City of Riverside Electric Utility's management. Our responsibility is to express an opinion on these financial statements based on our audits. The prior year partial comparative information has been derived from the financial statements of the Electric Utility for the year ended June 30, 2009 and, in our report dated October 29, 2009, we expressed an unqualified opinion on those financial statements.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America and the standards applicable to financial audits contained in *Government Auditing Standards*, issued by the Comptroller General of the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1 to the financial statements, the financial statements of the City of Riverside, California, Electric Utility are intended to present the balance sheets and the related statements of revenues, expenses and changes in equity, and cash flows for the City of Riverside, California, Electric Utility, a fund of the City, and do not purport to, and do not, present fairly the financial position of the City of Riverside, California, and the changes in its financial position and its cash flows, where applicable, in conformity with accounting principles generally accepted in the United States of America.

In our opinion, the financial statements referred to above present fairly, in all material respects, the balance sheets of the City of Riverside, California, Electric Utility, as of June 30, 2010, and the changes in its equity and its cash flows for the years then ended, in conformity with accounting principles generally accepted in the United States of America.

During the year ended June 30, 2010, the City of Riverside Electric Utility changed the manner in which it accounts for derivative instruments as a result of the implementation of GASB Statement No. 53, as described further in the notes to the financial statements.

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To the Honorable City Council and Board of Public Utilities
City of Riverside

The Management's Discussion and Analysis, as listed in the table of contents, is not a required part of the basic financial statements but is supplementary information. We have applied certain limited procedures, which consisted principally of inquiries of management regarding the methods of measurement and presentation of the required supplementary information. However, we did not audit the information and express no opinion on it.

Our audits were conducted for the purpose of forming an opinion on the financial statements that comprise the City of Riverside, California, Electric Utility's basic financial statements. The supplementary information entitled Electric Key Historical Data, as listed in the table of contents, is presented for the purpose of additional analysis and is not a required part of the basic financial statements. Such information has not been subjected to the auditing procedures applied in the audits of the basic financial statements and, accordingly, we express no opinion on it.

In accordance with *Government Auditing Standards*, we have also issued our report dated October 18, 2010 on our consideration of the City of Riverside's internal control over financial reporting and our tests of its compliance with certain provisions of laws, regulations, contracts, grant agreements and other matters. The purpose of that report is to describe the scope of our testing of internal control over financial reporting and compliance and the results of that testing, and not to provide an opinion on the internal control over financial reporting or on compliance. That report is an integral part of an audit performed in accordance with *Government Auditing Standards* and should be considered in assessing the results of our audit.

Mayer Hoffman McCann P.C.

San Jose, California
October 18, 2010

Management's Discussion and Analysis: Electric

As management of Riverside Public Utilities (a department of the City of Riverside), we offer the readers this narrative overview and analysis of the 2009-10 financial report for the period ended June 30, 2010 and 2009 for Riverside's Electric Utility, an enterprise fund of the City. We encourage readers to consider the information presented here in conjunction with additional information furnished in our financial statements, which begin on page 19 of this report. All amounts, unless otherwise indicated, are expressed in thousands of dollars.

FINANCIAL HIGHLIGHTS

Fiscal years 2010 and 2009 reflected strong operating results for the Electric Utility, with each year's retail revenues exceeding the previous all-time record, primarily from the effects of rate increases and an expanded customer base.

- Retail sales, net of reserve/recovery were $274,206 and $272,298 for years ended June 30, 2010 and 2009, respectively.
- The assets of the Electric Utility exceeded its liabilities (equity) at the close of fiscal years 2010 and 2009 by $440,051 and $398,266, respectively. Of this amount, $189,431 and $160,969, respectively, may be used to meet the Utility's ongoing obligations to creditors and customers.
- The Utility's overall equity increased by $41,785 and $41,969 for fiscal years ended June 30, 2010 and 2009 due to positive operating results from the historic levels of retail sales and other items discussed in this report.
- As of June 30, 2010 and 2009, unrestricted equity represented over 80% and 67% of annual operating expenses, respectively.

OVERVIEW OF THE FINANCIAL STATEMENTS

This discussion and analysis is intended to serve as an introduction to the City of Riverside Electric Utility financial statements. The Electric Utility is a department of the City of Riverside, and its activities are recorded in a separate enterprise fund. These financial statements include only the activities for the City of Riverside Electric Utility and provide comparative information for the last two fiscal years. Information on city-wide financial results is available in the City of Riverside's "Comprehensive Annual Financial Report."

The City of Riverside Electric Utility's financial statements are comprised of two components: 1) financial statements, and 2) notes to the financial statements. In addition, this report also contains other supplementary information to provide the reader additional information about the Electric Utility, including historical sales, operating, and other relevant data.

Included as part of the financial statements are three separate statements, which collectively provide an indication of the Electric Utility's financial health.

The ***Balance Sheets*** present information on assets and liabilities, with the difference between the two reported as equity. Over time, increases or decreases in equity may serve as a useful indicator of whether the financial condition of the Utility is improving or deteriorating.

The ***Statements of Revenues, Expenses and Changes in Equity*** present information showing how the Utility's equity changed during the most recent two fiscal years. Results of operations are reported as underlying events occur, regardless of the timing of cash flows. Thus, revenues and expenses are reported in these statements for some items that will result in cash flows in future fiscal periods, e.g., accounts payable and accounts receivable. This is called the accrual basis of accounting and is more fully described in the accompanying Notes to the Financial Statements.

The ***Statements of Cash Flows*** present the cash flow changes occurring during the last two fiscal years in highly liquid cash and cash equivalents, including certain restricted assets.

The ***Notes to the Financial Statements*** provide additional information that is essential to a full understanding of the data provided in the financial statements. The Notes to the Financial Statements can be found on pages 23 to 43 of this report.

UTILITY FINANCIAL ANALYSIS

As noted earlier, equity (also called net assets) may serve over time as a useful indicator of the fund's financial position. In the case of Riverside's Electric Utility, assets exceeded liabilities (equity) by $440,051 and $398,266 at the close of the fiscal years 2010 and 2009, respectively.

The following table summarizes the Utility's financial condition as of June 30, 2010, 2009 and 2008:

CONDENSED STATEMENTS OF EQUITY (NET ASSETS)

	2010	2009	2008
Current and other assets	$ 481,878	$ 474,306	$ 496,149
Capital assets	606,777	565,894	505,444
Total assets	1,088,655	1,040,200	1,001,593
Long-term debt outstanding	479,174	502,415	524,237
Other liabilities	169,430	139,519	121,059
Total liabilities	648,604	641,934	645,296
Invested in capital assets, net of related debt	222,016	208,695	185,759
Restricted	28,604	28,602	27,891
Unrestricted	189,431	160,969	142,647
Total equity (net assets)	$ 440,051	$ 398,266	$ 356,297

ASSETS

Fiscal Year 2010 The Utility's total assets of $1,088,655 reflect an increase of $48,455 (4.7%), primarily due to the following:

- Net capital assets (Utility plant) increased by $40,883, primarily due to an increase in completed distribution system assets of $30,176 resulting from continued improvements to the Electric Utility's distribution system and increases in construction in progress of $24,344 as a result of the continued construction of the Riverside Energy Resource Center (RERC) Units 3 and 4, offset by the current year impact of depreciation. Additional capital asset information can be found in the "Capital Assets and Debt Administration" section of the financial analysis.
- Current and other assets, comprised of restricted and unrestricted assets, had a net increase of $7,572. Unrestricted and other non-current assets increased by $50,822, offset by a decrease of $43,250 in restricted assets.
- Unrestricted and other non-current assets increased by $50,822 primarily due to an increase of $35,409 in operating cash and reserves resulting from positive operating results, an increase of $9,207 in deferred debits on interest rate swap fair valuation and an increase of $14,730 in the fair value of congestion revenue right derivatives as a result of the implementation of Governmental Accounting Standards Board Statement No. 53, *Accounting and Financial Reporting for Derivative Instruments* (GASB 53). See Note 1 and Note 9 in the accompanying financial statements for additional information. The increase was offset by $8,915 from net decreases in advances receivable from the City, deferred purchased power, accounts receivable, and prepaid expenses.
- The decrease of $43,250 in restricted assets was primarily due to the use of $48,583 of bond proceeds for capital projects offset by a $4,480 increase in nuclear decommissioning reserve.

Fiscal Year 2009 Total assets were $1,040,200, an increase of $38,607 (3.9 %), comprised of a $60,450 increase in Utility plant for improvements to the distribution system, including $32,488 for construction in progress, offset by a $21,843 decrease in current and other assets. The $21,843 decrease was primarily due to unrestricted and other non-current assets decreases of $33,586 in City advances, $4,700 accounts and accrued interest receivables and $3,341 in deferred purchased power, offset by increases of $14,323 in interest rate swaps and derivative instruments and $6,742 in net cash and cash equivalents.

LIABILITIES

Fiscal Year 2010 The Utility's total liabilities were $648,604, an increase of $6,670 (1.0%), due to the following:

- Long-term debt outstanding decreased by $23,241, primarily due to principal repayments and the amortization of bond premiums and deferred bond refunding costs.
- Other liabilities increased by $29,911, primarily due to increases of $9,208 in the fair value of interest rate swaps and $14,730 in deferred credits on congestion revenue rights resulting from the implementation of GASB 53 and $4,480 in nuclear decommissioning.

Fiscal Year 2009 Total liabilities were $641,934, a decrease of $3,362 (0.5%), primarily due to a decrease in long-term debt outstanding of $21,822, resulting from principal repayments and the amortization of bond premiums and deferred bond refunding costs and $6,768 in accounts payable, offset by an increase of $14,322 for interest rate swaps and deferred credits on congestion revenue rights related to GASB 53 implementation, $4,549 for nuclear decommissioning and $3,726 for capital leases and accrued interest payables.

EQUITY (NET ASSETS)

Fiscal Year 2010 The Utility's equity, which represents the difference between the Utility's resources and its obligations, totaled $440,051 an increase of $41,785 (10.5%), primarily due to rate increases and positive operating results and is comprised of the following:

- A portion of the Utility's equity (50.5%) reflects its investment in capital assets, such as production, transmission, and distribution facilities, less any related outstanding debt used to acquire those assets. This portion totaled $222,016, an increase of $13,321 (6.4%) primarily due to the amount of capital assets constructed or purchased that were not bond financed. Additional capital asset information can be found in the "Capital Assets and Debt Administration" section.
- The restricted portion totaled $28,604 (6.5% of total equity), and represents resources that are subject to internal and external restrictions on how they may be used. These are reserved for items such as debt repayment, Public Benefit Programs, and other legally restricted assets.
- The unrestricted portion equals $189,431, (43.0%of total equity), an increase of $28,462 (17.7%), and is primarily attributable to positive operating results. This portion may be used to meet the Utility's ongoing obligations to creditors and customers.

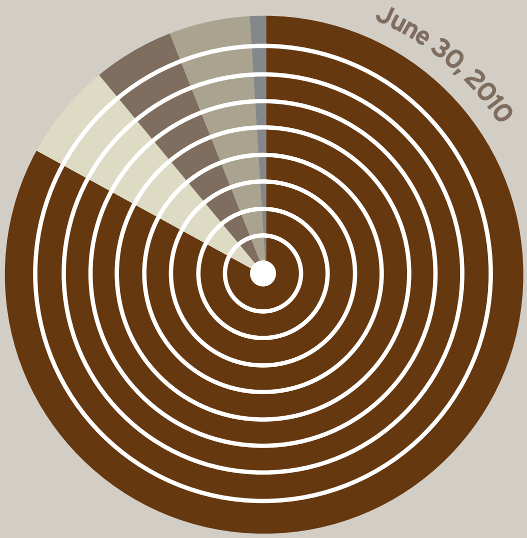
Fiscal Year 2009 Electric fund equity increased by $41,969 (11.8%) to a total of $398,266. The portion of equity investment in capital assets, net of related debt, increased by $22,936 primarily due to the amount of capital assets constructed or purchased that were not bond financed. The restricted portion increased by $711 due to an increase in the required debt service reserve offset by a decrease in Public Benefits Program's assets. The unrestricted portion increased by $18,322 and was attributable to positive operating results.

Positive operating results in the Electric Utility increased equity by $41,785 and $41,969 during fiscal years 2010 and 2009, respectively, as reflected in the following Condensed Statements of Changes in Equity:

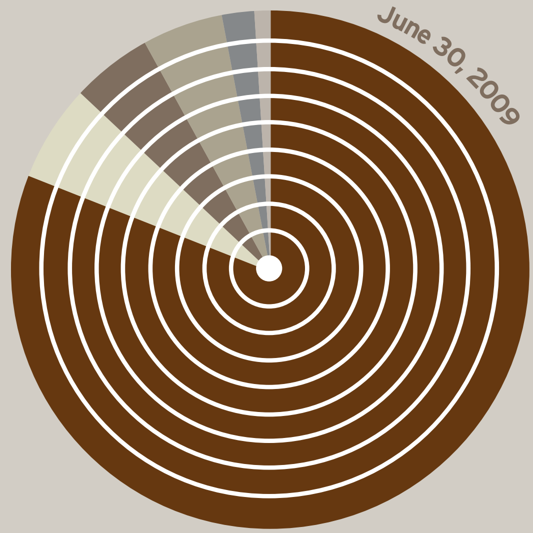
CONDENSED STATEMENTS OF CHANGES IN EQUITY (NET ASSETS)

	2010	2009	2008
Revenues:			
Retail sales, net	$ 274,206	$ 272,298	$ 257,120
Wholesale sales	1,466	4,674	6,959
Transmission revenues	21,100	18,673	19,211
Investment income	16,009	17,625	16,380
Other revenues	14,760	14,162	14,242
Capital contributions	3,477	7,060	6,076
Total revenues	331,018	334,492	319,988
Expenses:			
Production and purchased power	127,162	135,947	143,605
Transmission	33,030	32,677	31,288
Distribution	50,421	47,808	48,749
Depreciation	25,375	23,091	22,193
Interest expenses and fiscal charges	19,589	23,417	15,972
Total expenses	255,577	262,940	261,807
Transfers to the City's general fund	(33,656)	(29,583)	(27,371)
Changes in equity	41,785	41,969	30,810
Equity, July 1	398,266	356,297	325,487
Equity, June 30	$ 440,051	$ 398,266	$ 356,297

REVENUES BY SOURCES



- Retail Sales 83%
- Transmission Revenue 6%
- Investment Income 5%
- Other 5%
- Capital Contributions 1%
- Wholesale Sales 0%



- Retail Sales 81%
- Transmission Revenue 6%
- Investment Income 5%
- Other 5%
- Capital Contributions 2%
- Wholesale Sales 1%

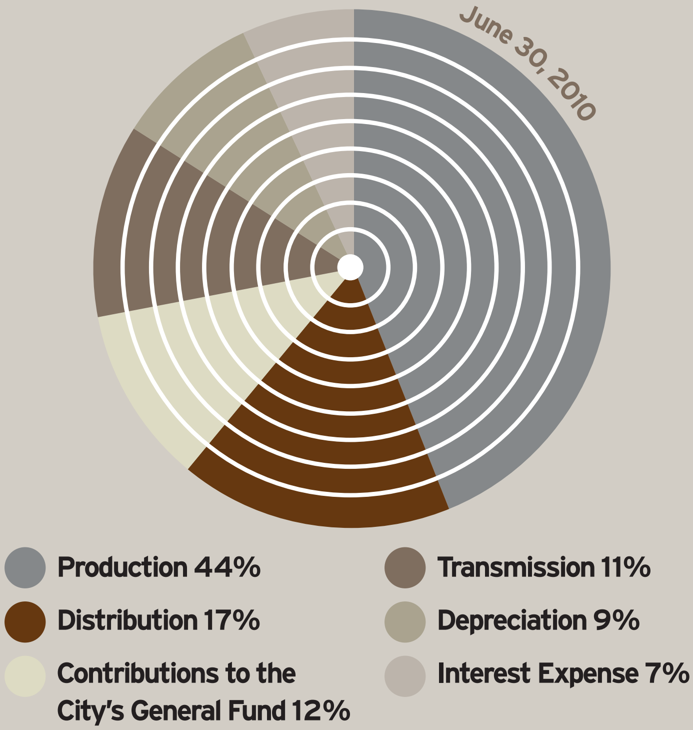
Fiscal Year 2010 Total revenues for the years ended June 30, 2010 and 2009 were $331,018 and $334,492, respectively, a decrease of $3,474 (1.0%), with changes in the following:

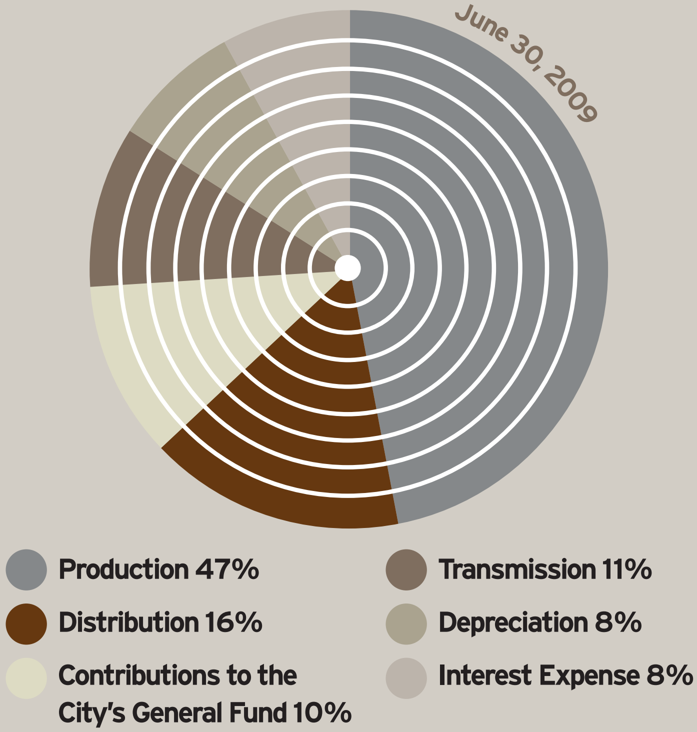
- Retail sales (residential, commercial, industrial, and other sales), net of reserve/recovery, totaled $274,206, a $1,908 (0.7%) increase. Retail sales continue to be the primary revenue source for the Electric Utility, accounting for 82.8% of total revenues. The increase was due to the positive effects of the rate increases on January 1, 2009 and January 1, 2010 as a result of the Electric Rate Plan, offset by a 4.7% reduction in retail consumption.
- Wholesale sales of $1,466 decreased by $3,208 (68.6%), due to a lower volume of "excess" power available for sale, and a lower overall price for market sales.
- Transmission revenues of $21,100 increased by $2,427 (13.0%), primarily due to higher transmission revenues authorized by the Federal Energy Regulatory Commission (FERC) as of July 1, 2009.
- Investment income of $16,009 reflects a decrease of $1,616 (9.2%), due to a decrease in a lower overall earnings rate in the current fiscal year.
- Capital contributions were $3,477, a decrease of $3,583 (50.8%) reflecting a lower level of construction projects funded by others due to the ongoing uncertain economic outlook.

Fiscal Year 2009 Total revenues were $334,492, an increase of $14,504 (4.5%), with significant changes in the following areas:

- Net retail sales of $272,298 (81.4% of total revenues) increased by $15,178 (5.9%). The increase was primarily due to the positive effects of rate increases on January 1, 2008 and January 1, 2009 as a result of the Electric Rate Plan.
- Wholesale sales of $4,674 decreased by $2,285 (32.8%), due to a lower volume of "excess" power available for sale, as well as lower prices received for market sales.
- Investment income of $17,625 reflected an increase of $1,245 (7.6%), due to positive operating results offset by a lower overall earnings rate.

EXPENSES BY SOURCES





Fiscal Year 2010 Total expenses, excluding general fund transfer, for the years ended June 30, 2010 and 2009 were $255,577 and $262,940, respectively, a decrease of $7,363 (2.8%). The decrease was primarily due to the following:

- Production and purchased power costs of $127,162 decreased by $8,785 (6.5%), primarily due to lower generation costs resulting from lower natural gas and power prices due to demand destruction as a result of the continuing economic decline.
- Distribution expenses of $50,421 increased by $2,613 (5.5%), primarily due to increases in personnel-related expenses.
- Depreciation expense of $25,375 increased by $2,284 (9.9%) primarily due to the completion of prior year distribution system assets.
- Interest expense and fiscal charges of $19,589 decreased by $3,828 (16.3%), primarily due to lower interest costs as a result of lower debt outstanding and an increase in capitalized interest resulting from the continued construction of RERC Units 3 and 4.

Fiscal Year 2009 Total expenses were $262,940, an increase of $1,133 (0.4%), due to the items discussed below:

- Production and purchased power costs of $135,947 decreased by $7,658 (5.3%), primarily due to lower generation costs due to excess market supply in a weakening economy and decreases in natural gas prices.
- Interest expense and fiscal charges of $23,417 increased by $7,445 (46.6%), primarily due to a full year of interest expense related to the 2008 Electric Revenue Series D Bonds.

TRANSFERS

Transfers to the City's general fund are limited to a maximum of 11.5% of the prior year gross operating revenues by Section 1204(f) of the City Charter. The City uses these funds to help provide needed public services to the residents of the City, including police, fire, parks, libraries and other benefits.

Fiscal Year 2010 The Electric Utility transferred $33,656, an increase of $4,073 (13.8%). This amount is approximately 11.4% of prior year's gross operating revenues less wholesale sales and Public Benefit Program revenues.

Fiscal Year 2009 The Electric Utility transferred $29,583 to the City's general fund. This amount was approximately 10.5% of prior year's operating revenues less wholesale sales and Public Benefit Program revenues.

CAPITAL ASSETS AND DEBT ADMINISTRATION

CAPITAL ASSETS

The Electric Utility's investment in Capital Assets includes investments in production, transmission, and distribution related facilities, land, construction in progress, nuclear fuel, as well as general items such as office equipment, furniture, etc.

The following table summarizes the Utility's capital assets, net of accumulated depreciation at June 30:

	2010	2009	2008
Production	$ 126,305	$ 129,051	$ 135,200
Transmission	16,313	16,003	16,046
Distribution	302,313	283,558	259,902
General	22,883	23,470	13,806
Land	7,612	7,612	7,149
Construction in progress	126,578	102,234	69,746
Nuclear fuel, at amortized costs	4,773	3,966	3,595
Total	$ 606,777	$ 565,894	$ 505,444

Fiscal Year 2010 The Electric Utility's investment in capital assets, net of accumulated depreciation, was $606,777, an increase of $40,883 (7.2%). The increase resulted primarily from the following significant capital projects:

- $6,429 for the City's portion of capital additions at the San Onofre Nuclear Generating Station (SONGS), including costs to replace the steam generators which will extend the life of the plant.
- $28,763 of expenditures related to the RERC Units 3 and 4 which will provide the Utility with 96 MW of additional generation facilities within the City limits.
- $4,278 for the initial stages of the Riverside Transmission Reliability Project (RTRP) and related reliability improvements to the City's Sub-Transmission System (STS) for additional generation import capability for a second point of interconnection with the state's high voltage transmission grid to serve future retail needs.
- $12,932 in additions and improvements to Electric facilities to serve existing and connect new customers.

Fiscal Year 2009 The Electric Utility's investment in capital assets, net of accumulated depreciation, was $565,894, an increase of $60,450 (12.0%). The increase resulted from $3,820 in expenditures for the City's portion of capital additions at SONGS, $36,554 of expenditures related to the RERC Units 3 and 4, $2,946 for the initial stages of the RTRP, $26,623 in additions and improvements to Electric facilities to serve existing and connect new customers and to provide additional centrally located office space for the Utility.

Additional information regarding capital assets can be found in Note 3 on 31 of this report.

DEBT ADMINISTRATION

The following table summarizes outstanding long-term debt (revenue bonds) as of June 30:

	2010	2009	2008
Revenue bonds	$ 501,600	$ 524,780	$ 545,125
Unamortized premium	11,421	9,760	10,931
Less:			
Current portion	(22,705)	(21,300)	(20,345)
Unamortized bond refunding costs	(11,142)	(10,825)	(11,474)
Total	$ 479,174	$ 502,415	$ 524,237

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 2.75, 2.58, and 2.62 at June 30, 2010, 2009 and 2008, respectively. This debt is backed by the revenues of the Utility (revenue bonds).

Fiscal Year 2010 Total long-term debt decreased by $23,241 (4.6%) to $479,174, due to $21,300 in principal repayments and the amortization of bond premiums and deferred refunding costs. On December 22, 2009, the Utility issued the 2009 Electric Refunding/Revenue Series A Bonds in the amount of $34,920 to advance refund the outstanding balance of the 1998 Electric Refunding/Revenue Bonds and a portion ($8,340) of the 2001 Electric Revenue Bonds.

Fiscal Year 2009 Total long-term debt decreased by $21,822 (4.2%) to $502,415, due to $20,345 in principal repayments and the amortization of bond premiums and deferred refunding costs.

Additional information on the Electric Utility's long-term debt can be found in Note 4 on pages 32 through 34 of this report.

CREDIT RATINGS

In November 2009, Standard & Poor's assigned a "AA-" long-term rating to the 2009 Electric Refunding/Revenue Series A Bonds and affirmed the "AA-" underlying rating on the Electric Utility's outstanding debt. The ratings reflect the Utility's "strong financial margins; strong liquidity position; continued strong growth in the Utility's service territory, customer accounts, and system peak loads; ongoing commitment toward obtaining renewable baseload and intermittent power through power purchase contracts; and a well-diversified resource portfolio that provides for very low-cost delivered power."

In November 2009, Fitch Ratings also assigned a "AA-" long-term rating to the 2009 Electric Refunding/Revenue Series A Bonds and affirmed the "AA-" rating on the Electric Utility's outstanding debt. The ratings reflect the Utility's "strong financial position with substantial reserves and debt service coverage; diverse power supply mix, which has historically provided a competitive cost of power in the California market; and a sizeable capital needs that will be funded almost entirely from additional debt issuance."

In January 2010, Standard & Poor's (S&P) corrected and lowered its rating on the Utility's variable rate, 2008 Electric Refunding/Revenue Series A, B, and C Bonds to "A+" from "AA-" reflecting S&P's rating of the bonds' letter of credit provider, Bank of America (to "A+" from "AA-"). The underlying S&P credit rating of the Electric Utility remains "AA-".

OTHER DEVELOPMENTS

ENVIRONMENTAL MATTERS

The City has a 7.6% contractual entitlement to the output of Units 1 and 2 at the Intermountain Power Project (see Note 8 for additional discussions), a 1,800 MW coal-fueled power plant located in Delta, Utah. Recent developments in federal and state environmental laws and regulations may impact operations at the plant, and could require significant capital expenditures at these facilities. The City will continue to monitor these laws and assess the impacts, if any, they will have on the operation of the plant through the contract expiration in 2027.

CLIMATE CHANGE

Cities have a compelling interest in reducing greenhouse gas emissions at the local level, especially as stakeholders and state agencies are working towards implementation of the California Global Warming Solutions Act (AB32, 2006).

Riverside Public Utilities (RPU) is committed to meeting or exceeding the Renewable Portfolio Standard (RPS) established by the State of California, as required of investor-owned utilities by the Public Utilities Code (SB 1078, 2002) and in keeping with the letter and spirit of the Public Utilities Code and the Health and Safety Code relating to air pollution (AB 32, 2006). With renegotiations of its existing renewable geothermal energy contracts with the Northwestern Band of Shoshone Nation (See Note 8 for discussions on Renaissance contracts), RPU has increased its current supply of electricity from renewable sources and RPU anticipates meeting its 2020 target of 33 percent of the City's electricity originating from renewable resources.

Senate Bill 1368 pertains specifically to power generation and long-term procurement of electricity, and requires the California Public Utilities Commission and the California Energy Commission to adopt GHG performance standards applicable to investor and publicly owned utilities. Baseload resources, greater than 5 MW and exceeding five years duration, must equal the performance of a combined-cycle gas turbine generator (e.g., emissions are limited to 1,100 pounds of carbon dioxide per megawatt hour).

On December 17, 2007, the City Council approved the Clean and Green Sustainable Riverside Action Plan to ensure sustainable growth while preserving the health of the local environment in Riverside for generations. On February 3, 2009, Riverside was the first California City to be designated as an "Emerald City" through the State of California Department of Conservation. Since this time the State worked with the City to focus on environmental priorities including water conservation, energy efficiency, solid waste reduction, motor vehicle and fuel use reduction, open-space land as well other topics. As the Pilot program comes to an end Riverside will continue to work towards sustainability through multiple programs and City wide initiatives based on the Green Action Plan.

Riverside continues to invest significant resources in providing energy supplies through clean natural resources and to explore new ideas and technologies that support the City's Clean and Green goal to become one of California's leading municipal power agencies in the use of renewable energy and reduction of greenhouse gas emissions. The City of Riverside is committed to working with regional, state and federal regulators to achieve this goal.

ECONOMIC FACTORS AND RATES

Although inflationary trends in the Riverside region generally compare favorably to the national indices, history has shown that certain costs such as purchased power during the California energy crisis can exponentially exceed inflation.

The FERC imposed $400/MWh price cap on purchased power (June 2001) expired with the California Independent System Operator's (CAISO) successful launch of the Market Redesign and Technology Upgrade (MRTU) on April 1, 2009, in order to implement a day-ahead wholesale electricity market, improve electricity grid management reliability, operational efficiencies and related technology infrastructure. In general, the energy bid cap is initially set at $500/MWh and will increase over time to $1,000/MWh. However, under certain transmission constraints, prices could exceed that amount, and are limited by the CAISO's price floor of ($2,500)/MWh and a price cap of $2,500/MWh, authorized by the FERC with a yet-to-be-determined sunset date. The CAISO continues to monitor and test the extreme price swings to ensure they aren't caused by the CAISO's very complex software systems. The new markets under MRTU present both risks and opportunities and are expected to impact costs to the City. The City is seizing the new opportunities without assuming additional risks in order to reduce overall costs to its ratepayers. The Utility continues to be vigilant in monitoring the MRTU outcomes, its active participation in the new market initiatives, and to implement changes to the appropriate systems, software and market strategies in the MRTU.

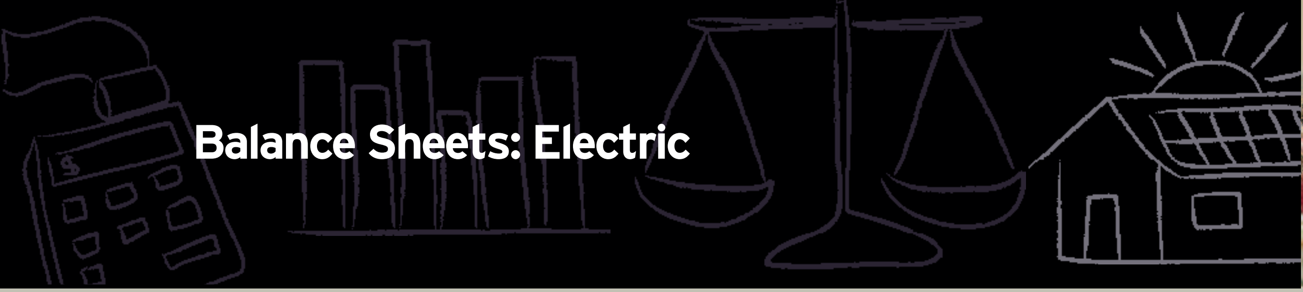
The MRTU markets continue to be favorable to load serving entities such as the City, although the power markets haven't been stressed due to generally milder weather patterns, low natural gas prices due to excess supply, and more importantly, the availability of excess generation due to the economic downturn and its impact on load reduction due to reduced power usage and high vacancies. Forward price curves have stabilized. However, regulatory actions and other factors, including volatility in natural gas and coal prices, low snowpack in the Pacific Northwest, high temperatures in Southern California, and transmission constraints or system integration under the complex CAISO business systems under a "stressed" MRTU market environment could impact future power rates.

The Utility has a green economic development plan, a multi-faceted strategic initiative that promotes economic development while remaining environmentally responsible. This plan, known as the Environmental and Economic Effectiveness Effort (E4) includes components for energy efficiency, renewable energy, green jobs, economic development and low income assistance. This plan includes an electric rate "freeze" through the end of 2012.

Proposals in the state and federal legislatures and other external factors could impact the revenues or costs of, and/or rates charged by the Utility depending on whether they are ultimately enacted and how they are implemented. These include a state, federal and/or regional cap and trade program (including the allocation of emission credits, availability of offsets, and the phase-in period to meet specific GHG emission reduction targets); additional renewable portfolio standard mandates—including eligibility requirements such as "simultaneous delivery", or in-state generation; California's ballot initiative to repeal AB 32, or an attempt by either the federal or state Environmental Protection Agency to implement GHG reduction measures; the California State Water Resources Control Board's final policy on once-through-cooling and its potential impact on SONGS and/or the wholesale energy markets; demand response and energy efficiency programs; cost allocation for federal and state high-voltage transmission infrastructure expansion, grid reliability enhancements, and renewable integration; continued disruption in the financial markets; California's MRTU markets under stressed conditions or impacts from future initiatives; and technological advances for carbon capture and geologic sequestration. Although the financial impacts to the Utility cannot be determined at this time, management is diligent in monitoring and analyzing these and other factors that could impact Utility operations, and proactively advocates solutions most beneficial or least harmful to its ratepayers.

REQUESTS FOR INFORMATION

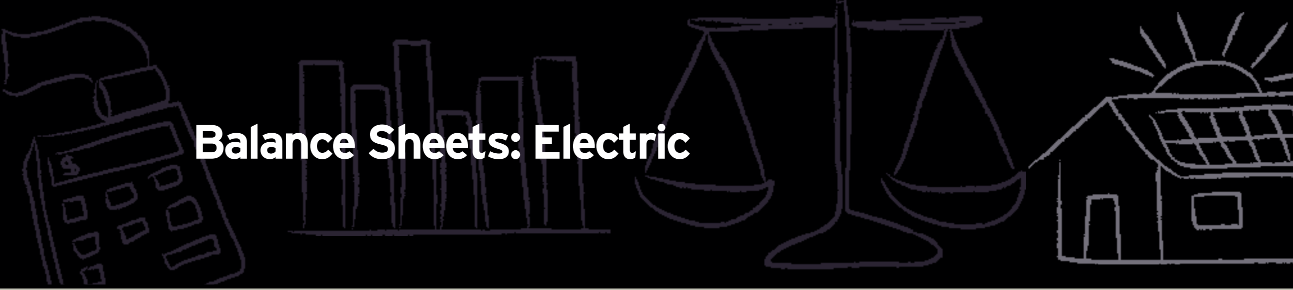
This financial report is designed to provide a general overview of the City of Riverside Electric Utility's finances. Questions concerning any information provided in this report or requests for additional financial information should be addressed to the Assistant General Manager Finance/Administration, Riverside Public Utilities, 3901 Orange Street, Riverside, CA 92501. Additional financial information can also be obtained by visiting www.riversidepublicutilities.com.



Balance Sheets: Electric

ASSETS	June 30, 2010	June 30, 2009
	(in thousands)	
UTILITY PLANT:		
Production	$ 274,030	$ 266,470
Transmission	28,484	27,544
Distribution	456,691	426,515
General	39,825	38,752
	799,030	759,281
Less accumulated depreciation	(331,216)	(307,199)
	467,814	452,082
Land	7,612	7,612
Construction in progress	126,578	102,234
Nuclear fuel, at amortized cost	4,773	3,966
Total utility plant (Note 3)	606,777	565,894
RESTRICTED ASSETS:		
Cash and cash equivalents (Note 2)	21,215	20,477
Cash and investments at fiscal agent (Note 2)	179,777	222,538
Total restricted non-current assets	200,992	243,015
OTHER NON-CURRENT ASSETS:		
Advances to City	650	5,918
Deferred pension costs (Note 1)	13,027	13,260
Deferred purchased power (Note 8)	-	1,670
Deferred bond issuance costs	6,847	7,523
Deferred debits (Note 4)	18,279	9,072
Derivative instruments (Note 9)	17,308	2,578
Total other non-current assets	56,111	40,021
Total non-current assets	863,880	848,930
CURRENT ASSETS:		
Unrestricted assets:		
Cash and cash equivalents (Note 2)	170,292	134,883
Accounts receivable, less allowance for doubtful accounts 2010 $2,003; 2009 $2,005	31,509	38,010
Accrued interest receivable	913	745
Prepaid expenses	10,748	6,224
Nuclear materials inventory	1,825	1,750
Derivative instruments (Note 9)	1,701	644
Total unrestricted current assets	216,988	182,256
Restricted assets:		
Cash and cash equivalents (Note 2)	7,168	8,328
Public Benefit Programs receivable	619	686
Total restricted current assets	7,787	9,014
Total current assets	224,775	191,270
Total assets	$ 1,088,655	$ 1,040,200

**See accompanying notes to the financial statements*



Balance Sheets: Electric

EQUITY AND LIABILITIES		June 30, 2010		June 30, 2009
		(in thousands)		
EQUITY:				
Invested in capital assets, net of related debt	$	222,016	$	208,695
Restricted for:				
Debt service (Note 5)		21,215		20,477
Public Benefit Programs		7,389		8,125
Unrestricted		189,431		160,969
Total equity		440,051		398,266
LONG-TERM OBLIGATIONS, LESS CURRENT PORTION (NOTE 4)		479,174		502,415
OTHER NON-CURRENT LIABILITIES:				
Pension obligation (Notes 1 and 4)		12,705		12,979
Nuclear decommissioning liability (Notes 1 and 4)		63,552		59,072
Postemployment benefits payable (Notes 1 and 4)		2,004		1,229
Derivative instruments (Note 4)		22,073		12,865
Deferred credits (Note 9)		17,308		2,578
Capital leases payable (Notes 1 and 4)		1,699		2,073
Total non-current liabilities		119,341		90,796
CURRENT LIABILITIES PAYABLE FROM RESTRICTED ASSETS:				
Accrued interest payable		4,085		4,454
Public Benefit Programs payable		396		888
Current portion of long-term obligations (Note 4)		22,705		21,300
Total current liabilities payable from restricted assets		27,186		26,642
CURRENT LIABILITIES:				
Accounts payable		18,314		18,657
Customer deposits		2,888		2,780
Deferred credits (Note 9)		1,701		644
Total current liabilities		22,903		22,081
Total liabilities		648,604		641,934
COMMITMENTS AND CONTINGENCIES (Notes 8 and 10)		-		-
Total equity and liabilities	$	1,088,655	$	1,040,200

**See accompanying notes to the financial statements*

Statements of Revenues, Expenses and Changes in Equity: Electric

	For the Fiscal Years Ended June 30, 2010	2009
	(in thousands)	
OPERATING REVENUES:		
Residential sales	$ 107,301	$ 105,525
Commercial sales	65,091	65,532
Industrial sales	97,458	97,100
Other sales	5,639	5,684
Wholesale sales	1,466	4,674
Transmission revenue	21,100	18,673
Other operating revenue	11,855	12,250
Total operating revenues before (reserve)/recovery	309,910	309,438
Reserve for uncollectible, net of bad debt recovery	(1,283)	(1,543)
Total operating revenues, net of (reserve)/recovery	308,627	307,895
OPERATING EXPENSES:		
Production and purchased power	127,162	135,947
Transmission	33,030	32,677
Distribution	50,421	47,808
Depreciation	25,375	23,091
Total operating expenses	235,988	239,523
Operating income	72,639	68,372
NON-OPERATING REVENUES (EXPENSES):		
Investment income	16,009	17,625
Interest expense and fiscal charges	(19,589)	(23,417)
Gain on retirement of utility plant	543	210
Other	2,362	1,702
Total non-operating revenues (expenses)	(675)	(3,880)
Income before capital contributions and transfers	71,964	64,492
Capital contributions	3,477	7,060
Transfers out - contributions to the City's general fund	(33,656)	(29,583)
Total capital contributions and transfers out	(30,179)	(22,523)
Increase in equity	41,785	41,969
EQUITY, BEGINNING OF YEAR	398,266	356,297
EQUITY, END OF YEAR	$ 440,051	$ 398,266

**See accompanying notes to the financial statements*

Statements of Cash Flows: Electric

	For the Fiscal Years Ended June 30, 2010	2009
	(in thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Cash received from customers and users	$ 315,305	$ 310,368
Cash paid to suppliers and employees	(207,844)	(211,112)
Other receipts	2,362	1,702
Net cash provided by operating activities	109,823	100,958
CASH FLOWS FROM NON-CAPITAL FINANCING ACTIVITIES:		
Transfers out - contributions to the City's general fund	(33,656)	(29,583)
Principal paid on pension obligation bonds	(274)	(227)
Advances to City	5,269	33,586
Net cash (used) provided by non-capital financing activities	(28,661)	3,776
CASH FLOWS FROM CAPITAL AND RELATED FINANCING ACTIVITIES:		
Purchase of utility plant	(60,218)	(72,900)
Purchase of nuclear fuel	(1,854)	(2,221)
Proceeds from the sale of utility plant	787	558
Deposit to escrow account for advanced bond refunding	(36,800)	-
Proceeds from revenue bonds, including premium	37,124	-
Principal paid on long-term obligations	(21,674)	(20,639)
Interest paid on long-term obligations	(23,404)	(23,950)
Capital contributions	1,610	1,493
Bond issuance costs	(348)	-
Net cash (used) by capital and related financing activities	(104,777)	(117,659)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Purchase of investment securities	(5,822)	(4,186)
Income from investments	15,841	19,674
Net cash provided by investing activities	10,019	15,488
Net (decrease) increase in cash and cash equivalents	(13,596)	2,563
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR (**including $159,100 and $212,733 at June 30, 2009 and June 30, 2008, respectively, reported in restricted accounts)**	293,983	291,420
CASH AND CASH EQUIVALENTS, END OF YEAR (**including $110,095 and $159,100 at June 30, 2010 and June 30, 2009, respectively, reported in restricted accounts**)	$ 280,387	$ 293,983
RECONCILIATION OF OPERATING INCOME TO NET CASH PROVIDED BY OPERATING ACTIVITIES:		
Operating income	$72,639	$ 68,372
Adjustments to reconcile operating income to net cash provided by operating activities:		
Depreciation	25,375	23,091
Amortization of deferred charges-pension costs	232	179
Amortization of nuclear fuel/purchased power	2,717	5,191
(Decrease) in allowance for uncollectible accounts	(2)	(211)
Decrease in accounts receivable	6,571	2,998
(Increase) decrease in prepaid expenses	(4,524)	786
(Increase) decrease in nuclear materials inventory	(75)	171
(Decrease) in accounts payable	(343)	(6,835)
Increase in postemployment benefits payable	775	624
(Decrease) increase in Public Benefit Programs	(492)	655
Increase (decrease) in customer deposits	108	(314)
Increase in decommissioning liability	4,480	4,549
Other receipts	2,362	1,702
Net cash provided by operating activities	$ 109,823	$ 100,958
SCHEDULE OF NON-CASH INVESTING, CAPITAL AND FINANCING ACTIVITIES:		
Capital contributions - capital assets	1,867	5,565
Borrowing under capital lease	-	2,433
Increase in fair value of investments	1,788	748

**See accompanying notes to the financial statements*

Note 1: Summary of Significant Accounting Policies

The Electric Utility exists under, and by virtue of, 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.

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 Electric Utility are also substantially in conformity with the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission (FERC). The Electric Utility is not subject to the regulations of the FERC. The Electric 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

Electric Utility customers are billed monthly. Unbilled electric service charges are recorded at year-end and are included in accounts receivable. Unbilled accounts receivable totaled $12,920 at June 30, 2010, and $12,609 at June 30, 2009.

An allowance for doubtful accounts is maintained for 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

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	12-30 years
Transmission and distribution plant	20-50 years
General plant and equipment	3-50 years

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 Electric Utility is charged one dollar per megawatt-hour of energy generated by the City's share of San Onofre Nuclear Generating Station's Units 2 and 3 to provide for estimated future storage and disposal of spent nuclear fuel. The Electric Utility pays this fee to its operating agent, Southern California Edison Co (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 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 City values its cash and investments in accordance with the provisions of the Governmental Accounting Standards Board 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, 2010, 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 pledged as collateral for payment of principal and interest on outstanding bonds, funds set aside to decommission the City's proportionate share of units 2 and 3 at the San Onofre Nuclear Generating Station, 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, 2010 and 2009 respectively are as follows: Regulatory Risk Reserve $15,000 and $4,000, Energy Risk Management Reserve $30,000 and $11,000 and Operating Reserve $80,531 and $86,531, for a combined total of $125,531 and $101,531 and are reflected in 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. As of June 30, 2010, only one advance, with no specified term remained outstanding. The balance of Advances to the City was $650 at June 30, 2010 and $5,918 at June 30, 2009.

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. The swaps are comprised of an “At-the-Market Swap” derivative instrument and an “Off-Market Swap” deferral balance as described below.

The Utility's evaluation of the “At-the-Market Swap” has concluded that it is an effective hedge under the synthetic instrument method. As a result, upon implementation of GASB 53 beginning July 1, 2009, the negative fair value of the “At-the-Market Swap” has been recorded and deferred on the Balance Sheets. The Balance Sheets for June 30, 2009 have been restated to reflect the retroactive application of GASB 53. Disclosure requirements are presented in Note 4 under Interest Rate Swaps on Revenue Bonds.

The “Off-Market Swap” deferral balance was a result of the refunding of the Auction Rate Security (ARS) debt that occurred in 2008. Based on the retroactive application of GASB 53, hedge accounting ceased to be applied on the interest rate swaps associated with the ARS upon the occurrence of the refunding. Since variable rate obligations were issued in the refunding, the deferral balance has been treated as a deferred loss and recorded on the Balance Sheets under long-term obligations.

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. GASB 53 allows an exception for the Balance Sheet deferral of effective hedges that meet the normal purchase and normal sales exception. It is the Utility's policy to apply the normal purchase and normal sales exception as appropriate.

The Utility has determined that congestion revenue rights (CRRs) associated with power transmission within the California Independent System Operator (CAISO) are its only derivative instruments under GASB 53 for this reporting year that do not meet the normal purchase and normal sales exception. CRRs are financial instruments that allow holders of such instruments to manage variability in transmission congestion costs. These CRRs are determined to be hedge effective under the consistent critical terms method, and as a result the positive fair value has been recorded and deferred on the Balance Sheets. The Balance Sheets for June 30, 2009 have also been restated to reflect the retroactive application of GASB 53. Disclosure requirements are presented in Note 9 – Other Derivative Instruments.

Note 1: Summary of Significant Accounting Policies (continued)

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 Electric 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 Electric 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 Electric Utility has set aside $63,552 in cash investments with the trustee as Riverside's estimated share of the decommissioning cost of San Onofre. The plant site easement at San Onofre terminates May 2050. The plant must be decommissioned and the site restored by the time the easement terminates.

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 provided over the seven year terms of the leases using the straight-line method.

For fiscal year ended June 30, 2010 and 2009, the total liability was $2,073 and $2,433, respectively, with the current portion included in accounts payable. The minimum annual lease payments for the life of the leases are $446 annually through fiscal year ended June 30, 2014, $433 in the fiscal year ended June 30, 2015, and $65 in the fiscal year ended June 30, 2016. Total future minimum lease payments are $2,281, with $208 representing interest and $2,073 representing the present value of the net minimum lease payments.

CUSTOMER DEPOSITS

The City holds customer deposits as security for the payment of utility bills. The Electric Utility's portion of these deposits as of June 30, 2010 and 2009 was $2,888 and $2,780, respectively.

COMPENSATED ABSENCES

The accompanying financial statements include accruals for salaries, fringe benefits and compensated absences due employees at June 30, 2010 and 2009. The Electric Utility treats compensated absences due employees as an expense and a current liability. The amount accrued for compensated absences was $4,046 at June 30, 2010, and $3,868 at June 30, 2009, and is included in accounts payable in the accompanying Balance Sheets.

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.

Note 1: Summary of Significant Accounting Policies (continued)

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 Electric 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, 2010, may be found in the notes to the City's "Comprehensive Annual Financial Report."

Although the ultimate amount of losses incurred through June 30, 2010 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 were $863 and $652 for the years ended June 30, 2010 and 2009, respectively. Any losses above the City's reserves would be covered through increased rates charged to the Electric Utility in future years.

EMPLOYEE RETIREMENT PLAN

The City contributes to the California Public Employees Retirement System (PERS), an agent multiple-employer public employee retirement system that acts as a common investment and administrative agency for participating public entities within the State of California.

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. 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 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 employer portion of the PERS funding as of June 30, 2010 and 2009 was 14.22 percent and 14.17 percent, respectively, of annual covered payroll. The Electric Utility pays both the employee and employer contributions. The total Electric Utility's contribution to PERS as of June 30, 2010 and 2009 was $6,735 and $5,733, respectively.

City-wide information concerning elements of the unfunded actuarial accrued liabilities, contributions to PERS for the year ended June 30, 2010 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, 2010.

PENSION OBLIGATION BONDS

In 2005, the City issued Pension Obligations Bonds in the amount of $60,000, of which the Electric Utility's 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, 2010 and 2009 was $13,027 and $13,260, 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, 2010.

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)

Note 1: Summary of Significant Accounting Policies (continued)

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 Electric 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 Electric Utility for the Stipend Plan are established and may be amended through the MOU between the City and the unions. The Electric Utility's contribution is financed on a "pay-as-you-go-basis" and the current contribution is unfunded. The contribution requirements of the Electric Utility's Implied Subsidy Plan are established by the City Council. The Electric 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 Electric Utility's annual OPEB cost (expense) for each plan is calculated based on annual required contribution of the employer (ARC), an amount actuarially determined in accordance with the parameters of GASB Statement No. 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 as of June 30, 2010 and 2009 was $2,004 and $1,229, 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, 2010 can be found in the notes to the City's "Comprehensive Annual Financial Report" for the fiscal year ended June 30, 2010.

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 Charter, the Electric Utility may transfer up to 11.5 percent of its prior year's gross operating revenues to the City's general fund. In fiscal years ended June 30, 2010 and 2009, the Electric Utility transferred approximately 11.4 and 10.5 percent of gross operating revenues less wholesale sales and Public Benefit Program revenues, or $33,656 and $29,583, respectively.

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.

Note 1: Summary of Significant Accounting Policies (continued)

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 Electric 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 government's prior year financial statements, from which this selected financial data was derived.

Note 2: Cash and Investments

Cash and investments at June 30, 2010 and 2009, consist of the following (in thousands):

	June 30, 2010	June 30, 2009
	Fair Value	
Equity interest in City Treasurer's investment pool	$ 198,675	$ 163,688
Investments at fiscal agent	179,777	222,538
Total cash and investments	$ 378,452	$ 386,226

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

	June 30, 2010	June 30, 2009
Unrestricted cash and cash equivalents	$ 170,292	$ 134,883
Restricted cash and cash equivalents	28,383	28,805
Restricted cash and investments at fiscal agent	179,777	222,538
Total cash and investments	$ 378,452	$ 386,226

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	$ 3,321	$ 3,321	$ -	$ -	$ -
Federal agency securities	40,056	5,500	2,212	16,655	15,689
Investment contracts [1]	112,343	81,712	-	11,571	19,060
Corp medium term notes	24,057	-	1,265	8,796	13,996
City Treasurer's investment pool [2]	198,675			198,675	
Total	$ 378,452	$ 90,533	$ 3,477	$ 235,697	$ 48,745

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

		Rating as of Year End		
Investment Type	Total	AAA	AA	Unrated
Held by fiscal agent				
Money market funds	$ 3,321	$ 3,321	$ -	$ -
Federal agency securities	40,056	40,056	-	-
Investment contracts	112,343	-	-	112,343
Corp medium term notes	24,057	-	24,057	-
City Treasurer's investment pool [2]	198,675			198,675
Total	$ 378,452	$ 43,377	$ 24,057	$ 311,018

[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, 2010 and 2009 (in thousands):

	Balance, As of 6/30/08	Additions	Retirements/ Transfers	Balance, As of 6/30/09	Additions	Retirements/ Transfers	Balance, As of 6/30/10
Production	$ 262,563	$ 3,907	$ -	$ 266,470	$ 7,560	$ -	$ 274,030
Transmission	26,972	572	-	27,544	940	-	28,484
Distribution	393,919	34,819	(2,223)	426,515	30,798	(622)	456,691
General	28,623	11,305	(1,176)	38,752	2,052	(979)	39,825
Depreciable utility plant	712,077	50,603	(3,399)	759,281	41,350	(1,601)	799,030
Less accumulated depreciation:							
Production	(127,363)	(10,056)	-	(137,419)	(10,306)	-	(147,725)
Transmission	(10,926)	(615)	-	(11,541)	(630)	-	(12,171)
Distribution	(134,017)	(10,816)	1,876	(142,957)	(12,043)	622	(154,378)
General	(14,817)	(1,604)	1,139	(15,282)	(2,396)	736	(16,942)
Accumulated depreciation	(287,123)	(23,091)	3,015	(307,199)	(25,375)	1,358	(331,216)
Net depreciable utility plant	424,954	27,512	(384)	452,082	15,975	(243)	467,814
Land	7,149	463	-	7,612	-	-	7,612
Construction in progress	69,746	83,555	(51,067)	102,234	65,695	(41,351)	126,578
Nuclear fuel	3,595	1,504	(1,133)	3,966	1,924	(1,117)	4,773
Nondepreciable utility plant	80,490	85,522	(52,200)	113,812	67,619	(42,468)	138,963
Total utility plant	$ 505,444	$ 113,034	$ (52,584)	$ 565,894	$ 83,594	$ (42,711)	$ 606,777

Note 4: Long-Term Obligations

The following is a summary of changes in long-term obligations during the fiscal years ended June 30, 2010 and 2009 (in thousands):

	Balance, As of 6/30/08	Additions	Reductions	Balance, As of 6/30/09	Additions	Reductions	Balance, As of 6/30/10	Due Within One Year
Revenue bonds	$ 544,582	$ -	$ (20,867)	$ 523,715	$ 36,401	$ (58,237)	$ 501,879	$ 22,705
Pension obligation	13,206	-	(227)	12,979	-	(274)	12,705	324
Postemployment benefits payable	605	624	-	1,229	775	-	2,004	-
Nuclear decommissioning liability	54,523	4,549	-	59,072	4,480	-	63,552	
Capital leases	-	2,728	(295)	2,433	-	(360)	2,073	374
Total long-term obligations	$ 612,916	$ 7,901	$ (21,389)	$ 599,428	$ 41,656	$ (58,871)	$ 582,213	$ 23,403

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

Revenue Bonds Payable	June 30, 2010	June 30, 2009
$98,730 1998 Electric Refunding/Revenue Bonds: All outstanding bonds were advance refunded on December 22, 2009 with the 2009 Electric Refunding/Revenue Bonds	$ -	$ 35,125
$47,215 2001 Electric Revenue Bonds: $47,215 serial bonds due in annual installments from $3,505 to $3,855 through October 1, 2012, interest from 4.0 percent to 5.0 percent; (partially advance refunded in 2005 and 2009)	11,030	22,740
$75,405 2003 Electric Refunding/Revenue Bonds: $75,405 serial bonds due in annual installments from $880 to $8,535 through October 1, 2013, interest from 4.0 percent to 5.0 percent	31,625	39,305
$27,500 2004 Electric Revenue Series A Bonds: $27,500 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.	16,295	19,305
$199,115 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, 2010 was 3.1 percent)	84,515	84,515
B - $57,275 2008 Series B Bonds - Variable rate bonds due in annual installments from $275 to $5,175 through October 1, 2035. Interest rate is subject to weekly repricing (net interest rate, including swaps, at June 30, 2010 was 3.2 percent)	56,725	57,000
C - $57,325 2008 Series C Bonds - Variable rate bonds due in annual installments from $300 to $5,200 through October 1, 2035. Interest rate is subject to weekly repricing (net interest rate, including swaps, at June 30, 2010 was 3.2 percent)	56,750	57,050
$209,740 2008 Electric Revenue Series D Bonds: $66,740 serial bonds due in annual installments from $125 to $7,735 from October 1, 2017 through October 1, 2038, interest from 3.63 percent to 5.0 percent; $48,015 term bonds due October 1, 2033, interest at 5.0 percent; $94,985 term bonds due October 1, 2038, interest at 5.0 percent	209,740	209,740
$34,920 2009 Electric Refunding/Revenue Series A Bonds: $34,920 fixed rate bonds due in annual installments from $450 to $6,105 through October 1, 2018, interest from 0.35 percent to 5.0	34,920	-
Total electric revenue bonds payable	501,600	524,780
Unamortized deferred bond refunding costs	(11,142)	(10,825)
Unamortized bond premium	11,421	9,760
Total electric revenue bonds payable, net of deferred bond refunding costs and bond premium	501,879	523,715
Less current portion	(22,705)	(21,300)
Total long-term electric revenue bonds payable	$ 479,174	$ 502,415

Note 4: Long-Term Obligations (continued)

Annual debt service requirements to maturity, excluding amounts for nuclear decommissioning liability, as of June 30, 2010, are as follows (in thousands):

	2011	2012	2013	2014	2015	2016-2020	2021-2025	2026-2030	2031-2035	2036-2039	Total
Principal	$ 22,705	$ 20,940	$ 21,905	$ 20,685	$ 14,480	$ 62,050	$ 66,245	$ 80,170	$ 97,870	$ 94,550	$ 501,600
Interest	20,283	19,385	18,415	17,415	16,629	75,954	65,238	50,931	32,800	9,549	326,599
Total	$ 42,988	$ 40,325	$ 40,320	$ 38,100	$ 31,109	$ 138,004	$ 131,483	$ 131,101	$ 130,670	$ 104,099	$ 828,199

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 2.75 and 2.58 at June 30, 2010 and 2009, 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 Electric Utility's financials statements. At fiscal year ended June 30, 2010, $17,600 of bonds outstanding are considered defeased.

ADVANCED REFUNDING

On December 22, 2009, $34,920, including premium, of Electric Refunding/Revenue Series A Bonds were sold with an all-in true interest cost of 1.97% to advance refund $28,460 all of the remaining 1998 Electric Refunding/Revenue Bonds, and $8,340, of the outstanding 2001 Electric Revenue Bonds. This fixed rate bond issue, with an interest rate ranging from 0.35% to 5.0%, is due in annual installments from $450 to $6,105 through October 1, 2018. The refunding was undertaken to reduce total debt service payments over the next 9 years by $4,012 and resulted in an economic gain of $3,729.

INTEREST RATE SWAPS ON REVENUE BONDS

The Electric Utility has three cash flow hedging derivative instruments, which are pay-fixed swaps. These swaps were determined to be hedge-effective under the synthetic instrument method. The changes in fair value during the reporting period were reported as deferred debits.

A summary of the derivative activity for the year ended June 30, 2010 is as follows:

	Notional Amount	Fair Value as of 6/30/10	Change in Fair Value for Fiscal Year
2008 Electric Refunding/Revenue Bonds Series A	$ 84,515	$ (8,747)	$ (4,062)
2008 Electric Refunding/Revenue Bonds Series B	$ 57,275	$ (6,649)	$ (2,569)
2008 Electric Refunding/Revenue Bonds Series C	$ 57,325	$ (6,677)	$ (2,577)

Objective: As a means to lower borrowing costs, when compared against fixed-rate bonds at the time of issuance in May 2008, the City entered into interest rate swap agreements in connection with its $199,115, Electric Refunding/Revenue Series A, B and C Bonds. The intention of the swap was to effectively change the City's variable interest rate on the bonds to a synthetic fixed rate of 3.11% for Series A, 3.20% for Series B and C.

Terms: Under the swaps, the City pays the counterparty a fixed payment as noted above 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. Beginning in fiscal year 2015 for the Series A bonds, and 2009, for the Series B and C bonds, respectively, the notional value of the swaps and the principal amount of the associated debt decline by $1,250 to $7,000 (Series A), $275 to $5,175 (Series B) and $275 to $5,200 (Series C), respectively, until the debt is completely retired in fiscal years 2030 (Series A) and 2036 (Series B and C), respectively.

Note 4: Long-Term Obligations (continued)

The bonds and the related swap agreements for the 2008 Electric Refunding/Revenue Series A Bonds mature on October 1, 2029 and Series B and C Bonds mature on October 1, 2035. As of June 30, 2010, rates were as follows:

		2008 Electric Refunding/ Revenue Series A Bonds	2008 Electric Refunding/ Revenue Series B Bonds	2008 Electric Refunding/ Revenue Series C Bonds
Interest rate swap:	Terms	Rates	Rates	Rates
Fixed payment to counterparty	Fixed	3.11100%	3.20100%	3.20400%
Variable payment from counterparty	62.68 LIBOR + 12bps	(0.73298%)	(0.73344%)	(0.69612%)
Net interest rate swap payments		2.37802%	2.46756%	2.50788%
Variable-rate bond coupon payments		0.74922%	0.74848%	0.69642%
Synthetic interest on bonds		3.12724%	3.21604%	3.20430%

Fair value: As of June 30, 2010, in connection with all swap agreements, the transactions had a total negative fair value of ($22,073). Because the coupons on the City'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 swap, 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, 2010, the City was not exposed to credit risk because the swap had a negative fair value. The swap counterparties, J.P. Morgan Chase Bank and Merrill Lynch Capital Services, 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 swap 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, 2010, there is no requirement for collateral posting for any of the outstanding swaps

Basis risk: As noted above, the swaps expose the City to basis risk should the relationship between LIBOR and the variable 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 City if either counterparty's credit quality falls below "BBB-" as issued by Standard & Poor's. The City 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 City 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, 2010, 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
2011	$ 575	$ 1,449	$ 4,818	$ 6,842
2012	2,650	1,430	4,753	8,833
2013	2,750	1,410	4,684	8,844
2014	2,850	1,389	4,613	8,852
2015	4,800	1,354	4,495	10,649
2016-2020	44,600	5,693	18,893	69,186
2021-2025	41,000	4,187	13,959	59,146
2026-2030	41,690	2,717	9,207	53,614
2031-2035	46,700	1,073	3,694	51,467
2036	10,375	-	-	10,375
Total	$ 197,990	$ 20,702	$ 69,116	$ 287,808

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 Riverside's electric revenue and refunding bonds require reserves that equate to the maximum annual debt service required in future years plus three months interest and nine months principal due in the next fiscal year. The 2008 Refunding/Revenue Series A, B and C Bonds require 110% of the monthly accrued interest to be included in the reserve. Additional reserves for the 1998 bonds (defeased on December 22, 2009) and the 2008 Revenue Series D Bonds are not required due to the purchase of surety bonds to cover the reserve requirements. The 2009 Refunding/Revenue Series A Bonds do not have an additional reserve requirement.

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 2009-10 and 2008-09 fiscal years, the Electric Utility paid approximately $15,151 and $17,792, 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 or transmission expense in the financial statements.

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

Pursuant to a settlement agreement with SCE, dated August 4, 1972, the City was granted the right to acquire a 1.79 percent ownership interest in 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 City entered into the SONGS Participation Agreement that sets forth the terms and conditions under which the City, through the Electric 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. Maintenance and operation of SONGS remain the responsibility of SCE, as operating agent for the City.

During 2006, the FERC, Nuclear Regulatory Commission (NRC) and the California Public Utility Commission (CPUC) approved the transfer of Anaheim's shares to SCE, and as a result, SCE's ownership was increased to 78.21 percent in SONGS Units 2 and 3.

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. During fiscal year ended June 30, 2006, the City Council approved participation in SONGS through the extended operations date. It has been reported that SCE is pursuing a license extension from the NRC to continue operations through 2042, although the City has not approved its participation in the project through the extended term.

SCE, as operating agent, declared an "operating impairment" due to deterioration of the steam generators (SGs), which would have likely resulted in permanent shutdown of the plant in 2009-2010 timeframe. The estimated cost to replace the SGs is $680,000, of which approximately $12,200 would represent the City's share. Replacement of the SGs is expected to enable plant operations through at least 2022, and perhaps beyond if NRC approval is obtained. The City Council has approved participation in the replacement of the SGs. The SG replacement for SONGS Unit 2 was completed in April 2010 and the SG replacement for Unit 3 is expected to commence in September 2010 and to be completed in December 2010.

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 $152,586 and $146,027 for fiscal years ended June 30, 2010 and 2009, respectively.

All acquisitions or construction of capital assets are depreciated through 2022, to include the construction recapture extension period. The accumulated depreciation amounted to $126,837 and $120,549 for the fiscal years ended June 30, 2010 and 2009, respectively. The Electric Utility made provisions for future decommissioning costs of $1,581 for both fiscal years plus earnings on the Decommissioning Trust Fund of $2,898 and $2,968 for fiscal years June 30, 2010 and June 30, 2009, respectively (see Note 1). The Electric Utility's portion of current and long-term debt associated with SONGS is included in the accompanying financial statements.

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

The Electric Utility is a member of the Southern California Public Power Authority (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 Electric Utility participates in projects developed by SCPPA, it has entered into Power Purchase or Transmission Service Agreements, entitling the Electric Utility to the power output or transmission service, as applicable, and the Electric 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 Electric 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	11.7 MW	2017	2030
Southern Transmission System	10.2 percent	195.0 WM	2027	2027
Hoover Dam Uprating	31.9 percent	30.0 MW	2017	2017
Mead-Phoenix Transmission	4.0 percent	12.0 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 Electric 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.

Interest rates on the outstanding debt associated with the take-or-pay obligations range from 3.50 percent to 6.38 percent. The schedule below details the amount of principal and interest that is due and payable by the Electric 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 Upgrading	Mead-Phoenix Transmission	Mead-Adelanto Transmission	All Projects
2011	$ 24,460	$ 662	$ 7,538	$ 708	$ 319	$ 3,100	$ 36,787
2012	23,070	666	7,936	706	318	3,090	35,786
2013	19,942	669	9,614	704	318	3,087	34,334
2014	22,708	672	8,764	705	318	3,092	36,259
2015	21,154	676	8,789	703	266	3,064	34,652
2016-2020	98,709	2,050	41,523	2,101	1,302	14,675	160,360
2021-2025	43,771	-	41,179	-	258	2,915	88,123
2026-2029	-	-	10,740	-	-	-	10,740
Total	$ 253,814	$ 5,395	$ 136,083	$ 5,627	$ 3,099	$ 33,023	$ 437,041

Note 8: Commitments (continued)

In addition to debt service, Riverside'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, 2010 and 2009, are as follows (in thousands):

FISCAL YEAR	Intermountain Power Project	Palo Verde Nuclear Generating Station	Southern Transmission System	Hoover Dam Upgrading	Mead-Phoenix Transmission	Mead-Adelanto Transmission	All Projects
2010	$ 27,458	$ 2,991	$ 1,779	$ 68	$ 40	$ 265	$ 32,601
2009	$ 28,010	$ 3,044	$ 1,975	$ 81	$ 121	$ 243	$ 33,474

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

The City has become a Participating Transmission Owner (see Note 10) 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 City receives reimbursement for, its revenue requirements, including the costs associated with these three transmission projects.

POWER PURCHASE AGREEMENTS

The Electric Utility has executed two firm power purchase agreements with Bonneville Power Administration (BPA). The minimum annual obligation for fiscal year 2010-2011 is $636. The first agreement with BPA is 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. 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.

The Electric Utility had an agreement with Deseret for five megawatts of capacity and associated energy from January 1, 1992, through December 31, 1994, then increasing to 52 megawatts of capacity and associated energy through December 31, 2009. A notice of termination of the power purchase agreement was provided to Deseret effective March 31, 1998, resulting in litigation which was settled on July 31, 1999. Under the terms of the settlement agreement, the notice of termination was rescinded and the power purchase agreement was amended to reflect substantial price reductions after fiscal year 2002 through the term of the agreement in 2009. In exchange, Riverside Public Utilities paid Deseret $25,000 from Electric fund reserves, which was reflected on the Balance Sheets as Deferred purchased power. On July 1, 2002, the Electric Utility began to amortize the $25,000 over the term of the agreement using the straight-line method, and the remaining balance was fully amortized when the agreement was terminated on December 31, 2009.

There was no deferred purchased power for Deseret as of June 30, 2010 and $1,670 in 2009, and the Utility had recorded amortization of $1,670 and $3,341 in fiscal years ended June 30, 2010 and June 30, 2009, respectively.

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 revenue-raising measures to pay claims, including a possible additional assessment on all licensed reactor operators.

Note 8: Commitments (continued)

RENEWABLE PORTFOLIO STANDARD (RPS)

On June 6, 2003 and July 8, 2003, the Public Utilities Board and the City Council respectively, adopted a RPS to increase procurement of renewable resources to reach a target of 20% of the Utility's energy by 2015. On March 16, 2007, the Public Utilities Board approved a new RPS, increasing the targets to 20% and 25% by 2010 and 2015, respectively. On May 4, 2007, the Public Utilities added an additional target of 33% by 2020. The City Council, on December 9, 2008, unanimously approved the revised RPS.

The contracts in the following table were executed as part of compliance with this standard. The Utility also has an agreement with Bonneville Power Administration for the purchase of energy credits that add to the total renewable portfolio. In the current fiscal year, renewable resources provided 17% of retail energy requirements of total power produced or purchased, and the Utility anticipates attaining the 20% goal by calendar year end.

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

Supplier	Type	Maximum Contract	Contract Expiration	Estimated Annual Cost For 2011
Salton Sea Power LLC	Geothermal	46.0 MW	5/31/2020	$ 21,139
Wintec	Wind	8.0 MW	11/10/2021	198
Total		54.0 MW		$ 21,337

All contracts are contingent on energy production from specific related generating facilities. Riverside 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 Power Purchase Agreement between Salton Sea and the City. The agreement increases the amount of renewable energy available to the City 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 City is only obligated for purchases of energy delivered to the City.

On November 10, 2006, the City of Riverside entered into a second Renewable Power Purchase Agreement with Wintec Energy, Ltd for wind generation capacity of up to 8 MW. The contract term is for 15 years, with additional capacity available upon completion of Wintec's Facility II Wind Turbine Project. The developer is encountering challenges in finding suitable wind turbines to complete the project and the project is expected to continue to be delayed.

On June 19, 2008, and December 12, 2008, respectively the City of Riverside entered into two separate Renewable Power Purchase Agreements with Shoshone Renaissance, LLC (Renaissance). The contract term for each agreement is 30 years, and provides a combined 96 megawatts of geothermal energy. Like the majority of renewable projects, Renaissance continues to experience difficulty securing financing due to the meltdown in the financial markets. The agreements have expired. However, Riverside and Renaissance are currently renegotiating the agreements to provide a more realistic development schedule. The renegotiations are expected to be completed by November 2010. The expected commercial operational date of the project is mid 2014 (delayed by two years) with reduced MW (from 64 MW to 46 MW). The parties are not planning to renegotiate the second agreement at this time. Similar to other renewable power purchase agreements, Riverside's payment obligation is limited to the amount of energy delivered.

CONSTRUCTION COMMITMENTS

As of June 30, 2010, the Electric Utility had major commitments (encumbrances) of approximately $18,748 with respect to unfinished capital projects, of which $17,787 is expected to be funded by bonds and $961 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, 2010, the Electric Utility has net commitments for fiscal year 2011, of approximately $11,710, with a market value of $9,997.

Note 9: Other Derivative Instruments

The Utility continually strives to optimize its resource portfolio using the selection of available energy and/or gas resources to serve the Utility's load obligations to capture the lowest economic value. The Utility makes frequent load projections at various points in time based on, among other factors, estimates of customer usage, weather, historical data, and contract terms. The Utility also frequently projects resource availability at various points in time based on variables such as availability of generating units, historic and forward market information, contract terms, and experience. The Utility uses these projections to purchase and sell quantities of wholesale electric capacity and energy at specified time(s) in the future, to match expected resources to projected load requirements.

The Utility is exposed to various market risks associated with its resource portfolio management and uses derivative and non-derivative instruments, as appropriate, to manage these risks. To help limit the Utility's exposures and risks to a tolerable level, the Utility has an approved Power Resources Risk Management Policies governing the types of transactions and delegations of authority deemed appropriate. The volumes of forward transactions for the Utility's short and long positions require Risk Management Committee approvals.

COMMODITY PRICE RISK

The Utility is exposed to commodity price risk due to the potential fluctuation in the market price of the commodity being traded and is influenced primarily by supply and demand. Commodity price risk may also be influenced by the number of active, creditworthy market participants, and the extent that nonperformance by market participants of their contractual obligations and commitments impacts the supply of, or demand for, the commodity.

The Utility's price exposure relates to the quantities of energy purchased and sold in the CAISO's Market Redesign and Technology Upgrade (MRTU) market as a result of differences between the Utility's load requirements versus the amount of energy delivered from its ownership or entitlement interest in generating facilities and bilateral contracts.

The Utility's hedging program reduces ratepayer exposer to variability in market prices related to its power and gas activities. The Utility's Power Resources Risk Management Policies govern the types of allowable hedging transactions (which include transactions considered derivatives as defined by GASB 53) and these include commodity options, swaps, forward arrangements, and congestion revenue rights (CRRs). The Risk Management Committee meets regularly to among other things, review and evaluate commodity positions, and approve hedging strategies, and the types of authorized transactions.

CREDIT RISK

The Utility's credit risk relates to potential losses incurred due to nonperformance by counterparties of their contractual obligations to deliver energy or make financial settlements. Changes in market prices may dramatically alter the size of credit risk with counterparties, even when conservative credit limits are established. The Utility has an approved Wholesale Counterparty Risk Management Policy and seeks to mitigate credit risk by entering into bilateral contracts that specify credit terms and protections against default; applying credit limits and duration criteria to existing and prospective counterparties; and actively monitoring current credit and default exposures. The Utility contracts with renewable power producers that are typically below investment grade, and limits exposure through take-and-pay contracts in which the Utility only pays for the renewable energy delivered. The Utility also seeks performance assurance through collateral requirements in the form of letters of credit, parental guarantees or prepayments.

The Utility has concentrations of suppliers including: electric and gas utilities, electric generators and transmission providers, financial institutions and energy marketing and trading companies. In addition, the Utility has geographic concentrations of credit risk due to operations in the western United States. These concentrations may impact the Utility's overall exposure to credit risk, either positively or negatively, because counterparties may be singularly affected by changes in conditions.

The Utility transacts within the CAISO, which has its own credit and collateral posting requirements for entities participating in its markets. If a CAISO market participant defaults on its payment obligations, the CAISO first accesses the defaulting entity's credit enhancements with the CAISO. Under the currently effective MRTU tariff in effect as of June 30, 2010, any deficiency above those credit enhancements would be shared by all CAISO participants that are net creditors. The relevant portions of the MRTU tariff relating to credit and credit enhancements are currently under review at the FERC and may be subsequently amended or modified.

CONTINGENT FEATURES/CREDIT RELATED EXPOSURE

Certain derivative contracts contain collateral requirements, which vary depending on the level of unsecured credit expended by the counterparties, changes in market prices relative to contractual commitments, and other factors. If the Utility's credit rating falls below investment grade, the Utility may be required to pay the derivative liability or post additional collateral. The Utility's rating is AA- by both Fitch Ratings and Standard & Poor's, and the Utility has not posted any collateral relating to its derivative activities.

Certain power or gas contracts contain a provision for early termination at fair market value if either party determines that the counterparty is no longer creditworthy. Early termination of these contracts may require a payment by the Utility, or entitle the Utility to receive payment, for the difference between the contract and current market prices.

OTHER OPERATIONAL AND EVENT RISK

There are other operational and event risks that can affect the supply of the commodity and the Utility's operations. Other risks include regional planned and unplanned generation outages, transmission constraints or disruptions, environmental regulations that influence the availability of generation resources, seasonal periods of extreme high or low temperatures, and overall economic trends.

CAISO WHOLESALE ENERGY MARKETS

California's wholesale electricity market is operated by the CAISO. In 2006, the CAISO began its MRTU program to redesign and upgrade the wholesale energy markets across its controlled grid. The MRTU allows scheduling power in hourly increments with hourly prices through a day-ahead and real-time market that combines energy, ancillary services, unit commitment, and congestion management. MRTU became effective in March 2009 (for trade date April 1, 2009) and the Utility began participating in the day-ahead and real-time markets for the sale of its generation and purchases of its load requirements.

The MRTU structure uses a nodal locational pricing model, which sets wholesale electricity prices at 3,000 different system points (nodes) that reflect local generation and delivery costs, as opposed to the previous system of three broad zonal prices. Generally, the Utility schedules its electricity generation assets to serve its load. However, when it has excess generation or when the market price of power is more economic than its own generation, the Utility may sell power from utility owned generation assets and existing power procurement contracts into, or buy generation and/or ancillary services to meet its load requirements from, the Integrated Forward Markets.

Note 9: Other Derivative Instruments (continued)

Although to date the markets in general have been stable and prices remain relatively low, if the new market mechanisms created by MRTU result in any significant price/market flaws that are not promptly and effectively corrected by the market mechanisms, the CAISO or the FERC, or if the Utility's CRRs are not sufficient to hedge the financial risk associated with the CAISO's congestion costs under MRTU, or if either the CAISO's or the Utility's MRTU-related business systems and software do not perform as intended, the Utility's financial conditions, results of operations, and cash flows could be materially and adversely affected.

Congestion Risk: The Utility will offer to buy its generation at nodes near the source of the generation, but will take delivery at the Utility's Metered Subsystem Load Aggregation Point (MLAP). Congestion may occur when available energy cannot be delivered to all loads due to transmission capacity constraints, which results in transmission congestion charges and differences in prices at various nodes. To help mitigate the variability of congestion costs, the CAISO offers CRRs--a financial commodity that entitles the holder to receive (or pay) the value of transmission congestion between specific nodes, acting as an economic hedge against transmission congestion charges. CRRs are offered by the CAISO through its allocation and auction processes.

The only Utility derivative commodity activity not meeting the normal purchase and normal sales exception criteria of GASB 53 relates to the Utility's CRRs. The Utility has been allocated long-term CRRs through 2019 related to its load and long-term resource entitlements, has acquired via auction certain CRRs as of June 30, 2010 and 2009, and anticipates acquiring additional CRRs through the allocation and auction phases. These are considered derivative instruments and were determined to be hedge-effective under the consistent critical terms method. The following is a summary of the derivative activity as of June 30, 2010 and 2009.

	Notional	Fair Value as of June 30, 2010			Changes in Fair Value		
Cash Flow Hedges	(in thousands)	Classification		Amount	Classification		Amount
Congestion Revenue Rights	13,813 MWhs	Derivative Instruments	$	19,009	Deferred Credits	$	15,787

	Notional	Fair Value as of June 30, 2009			Changes in Fair Value		
Cash Flow Hedges	(in thousands)	Classification		Amount	Classification		Amount
Congestion Revenue Rights	4,161 MWhs	Derivative Instruments	$	3,222	Deferred Credits	$	3,222

Terms: The CAISO releases CRRs through an annual and monthly process, each of which includes: 1) an Allocation phase, in which Load-Serving Entities (LSE) are allocated CRRs at no cost based on retail customer load demand, and 2) an Auction phase, in which CRRs are purchased at closing bid price. The CAISO also allocates long-term CRRs based on a combination of an LSE's retail load and the location of its long-term resource entitlements. CRRs are allocated by time of use (on- or off-peak). Annual and long-term CRRs are allocated by season. Annual CRRs are for one calendar year, with long-term CRRs having a term of 10 years. As of June 30, 2010, the Utility has monthly, annual, and long term CRRs for the period July 2010 through December 2019.

Fair Value: As of June 30, 2010 and 2009, the CRRs had a total fair value of $19,009 and $3,222, respectively. Due to the lack of a robust market for CRRs, the fair value was based on historical results using the CAISO Locational Marginal Price (LMP)-Marginal Congestion Cost (MCC) pricing information.

For each CRR, the Utility identified the historical MCC for the source (injection) CAISO node and the Utility's MLAP. This historical cost information was used to determine the average heavy-load (HL) and light-load (LL) MCC price difference for July 1, 2009 through June 30, 2010. Although the MRTU markets were launched in March 2009, a July 1st date was used to avoid unstable price effects immediately after the MRTU start-up. Historical prices were used to conservatively project the future value of the CRRs, present valued back to June 30, 2010 or 2009, respectively. As more pricing data becomes available, the Utility intends to use a rolling-3 year average of monthly congestion costs to project the value of its CRRs.

Termination risk: The CAISO's CRR allocation methodology is established in the MRTU tariff. Early termination would require tariff modifications and the Utility would participate in this regulatory process to help ensure that its interests in hedging future congestions costs are protected.

Rollover risk: The Utility's long term CRRs are effective through 2019. As the first year expires, the CAISO will undertake a new allocation process in which a portion of CRRs will be freely allocated based on an entity's load and long-term contracted resources. The Utility anticipates that it will receive a similar allocation assuming it continues to maintain long-term resources in the geographic proximity to those currently existing.

Realized gains and losses on effective derivative instruments related to power supply activities are included in either transmission or production and purchased power expense on the Statement of Revenues, Expenses and Changes in Equity.

Note 10: Litigation

The City continues to participate in key FERC dockets impacting the City's Electric Utility, such as the CAISO's MRTU.

On January 1, 2003, the City became a Participating Transmission Owner (PTO) with the CAISO, entitling the City to receive compensation for use of its transmission facilities committed to the CAISO's operational control. The compensation is based on the City's Transmission Reserve Requirements (TRR) as approved by the FERC.

On May 6, 2009, Riverside filed a revised TRR at FERC. In its filing, Riverside updated its projected transmission costs and proposed an automatic adjustment mechanism to reflect its actual costs incurred under existing transmission contracts with Southern California Edison which have become the most volatile component of its TRR. Numerous parties filed timely motions to intervene, with some parties protesting various portions of the TRR. On February 5, 2010, FERC approved a settlement agreement between Riverside and all intervening parties which resolved the case. Under the terms of the settlement agreement, Riverside's TRR was increased to $19,774,824 (95% of what was requested). Riverside will also be allowed to automatically recover further cost increases imposed by Southern California Edison without filing an application with FERC for a new TRR tariff, and must file its third TRR no later than December 31, 2011.

During the California Energy Crisis of 2001-2002, the City 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 (PX) who filed for Chapter 11 bankruptcy in 2001, the City was not paid for many of these transactions. On June 4, 2008, the FERC approved a settlement agreement between the City and numerous California entities, including all of the Investor-Owned Utilities and the California Attorney General, under which the City was paid all of its unpaid receivables, plus interest, minus $1.27 million in refunds. The net payout to the City was $3.7 million (including all unpaid receivables, including interest and its deposit with the Cal PX, minus $269,000 paid to the City of Banning for transactions made on its behalf by the City). Under the settlement, the City may receive additional distributions of refunds from other sellers. The City 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 City.

The Electric Utility is a defendant in various lawsuits arising in the normal course of business. Present lawsuits and other claims against the Electric Utility are incidental to the ordinary course of operations of the Electric 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 Electric Utility.

Note 11: Subsequent Event

The City of Riverside 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) from Corona. Clearwater is a combine-cycle, natural gas generating facility with a gross plant output of 29.5 MW. Following a "transition period" during which Riverside engaged in pre- closing activities and due diligence inspection, the transaction closed on September 1, 2010 and the City 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 is $45.6 million, and will be funded through a series of semi-annual payments ranging from $1.2 to $2.7 million through 2013, and $0.2 through $0.4 million from 2014 through 2015. In addition, two payments of $36.4 and $7.4 million are due 2013 and 2015, respectively, and will be funded primarily from bond proceeds.

Key Historical Operating Data: Electric

POWER SUPPLY (MWH)

	2009/10	2008/09	2007/08	2006/07	2005/06
Nuclear					
San Onofre	240,000	281,400	286,500	310,400	275,100
Palo Verde	96,300	97,700	85,200	90,000	72,600
Coal					
Intermountain Power	1,068,500	1,051,200	1,094,100	1,130,000	1,091,000
Deseret	187,400	406,000	427,600	400,000	396,000
Hoover (Hydro)	30,000	32,500	33,700	34,500	35,100
Gas					
Springs	1,400	3,300	2,300	1,600	1,600
RERC	11,500	48,700	46,800	62,000	9,300
Renewable Resources	354,900	233,000	247,800	245,000	264,000
Other purchases	276,500	349,200	594,100	462,000	517,300
Exchanges In	92,700	90,000	115,700	107,400	89,900
Exchanges Out	(156,200)	(160,600)	(202,600)	(191,900)	(174,600)
Total:	2,203,000	2,432,400	2,731,200	2,651,000	2,577,300
System peak (MW)	560.3	534.1	604.4	586.3	550.6

ELECTRIC USE

Number of meters as of year end	2009/10	2008/09	2007/08	2006/07	2005/06
Residential	95,258	95,214	94,691	94,232	93,607
Commercial	10,073	10,178	10,258	10,063	10,038
Industrial	916	904	978	837	496
Other	88	89	88	94	153
Total:	106,335	106,385	106,015	105,226	104,294
Millions of kilowatt-hours sales					
Residential	701	733	734	748	697
Commercial	406	433	441	456	474
Industrial	906	946	960	924	810
Other	32	33	34	39	57
Subtotal:	2,045	2,145	2,169	2,167	2,038
Wholesale	44	137	357	295	321
Total:	2,089	2,282	2,526	2,462	2,359

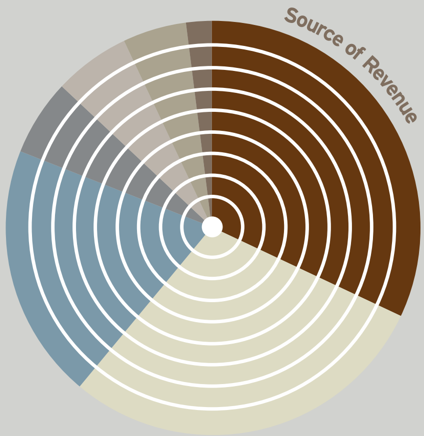
ELECTRIC FACTS

	2009/10	2008/09	2007/08	2006/07	2005/06
Average annual kWh per residential customer	7,397	7,739	7,779	7,959	7,515
Average price (cents/kWh) per residential customer	15.31	14.39	13.61	12.62	12.22
Debt service coverage ratio	2.75	2.58	2.62	3.09	2.67
Operating income as a percent of operating revenues	23.5%	22.2%	16.4%	22.0%	18.2%
Employees[1]	427	416	405	367	338

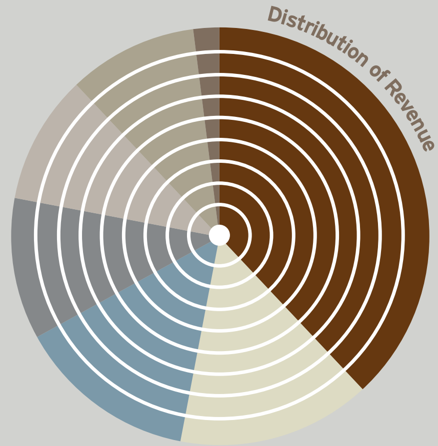
[1] Approved Positions

Key Historical Operating Data: Electric

2009/2010 ELECTRIC REVENUE AND RESOURCES

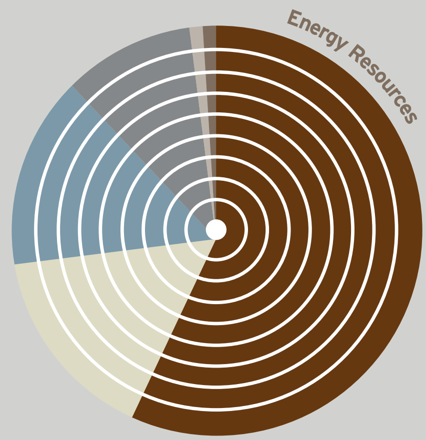


- Residential Sales 32¢
- Industrial Sales 29¢
- Commercial Sales 20¢
- Other Revenue 6¢
- Transmission Revenue 6¢
- Investment Income 5¢
- Other Sales 2¢
- Wholesale Sales 0¢



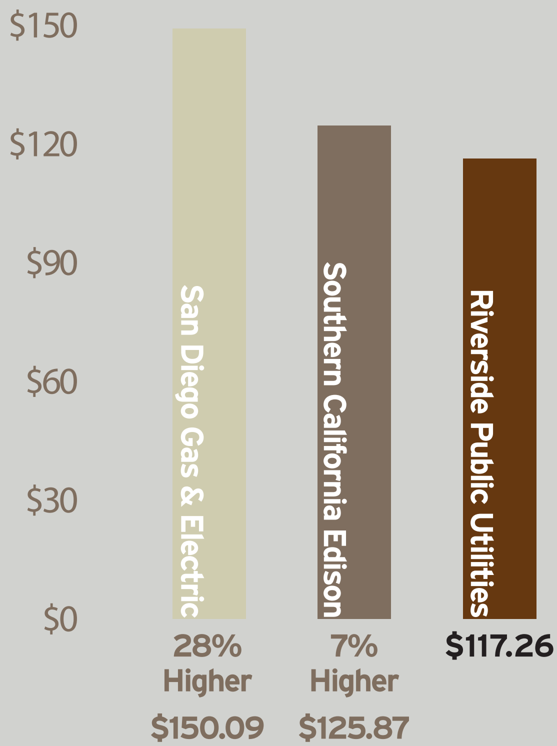
- Production 38¢
- Distribution 15¢
- Debt Service 14¢
- Additional Reserves 11¢
- Transfers to the City's General Fund* 10¢
- Transmission 10¢
- Additions and Replacements to the System 2¢

** Based on transfer of 11.4% of fiscal year 2008/2009 operating revenues (excludes wholesale sales and Public Benefits Program revenues).*



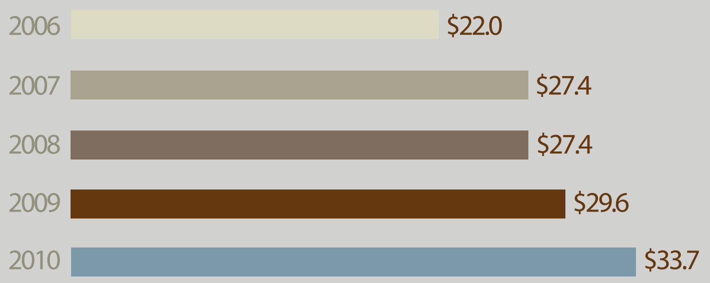
- Coal 57%
- Renewables 16%
- Nuclear 15%
- Other Purchases 10%
- Hydropower 1%
- Gas 1%

RESIDENTIAL ELECTRIC RATE COMPARISON – 750 KWH PER MONTH (AS OF JUNE 30, 2010)



Key Historical Operating Data: Electric

GENERAL FUND TRANSFER (IN MILLIONS)



NUMBER OF METERS AT YEAR END

TOTAL OPERATING REVENUE (IN MILLIONS)

PRODUCTION (IN MILLION KILOWATT-HOURS)*

** Energy shown before losses net of exchanges*

PEAK DAY DEMAND (IN MEGAWATTS)

ELECTRIC FACTS AND SYSTEM DATA

Established	1895
Service Area Population	304,051
Service Area Size (square miles)	81.5
System Data:	
Transmission lines (circuit miles)	91.1
Distribution lines (circuit miles)	1,301
Number of substations	14
2009-2010 Peak day (megawatts):	560
Highest Single hourly use:	
09/02/2009, 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 (1 representing the lowest risk and 4 representing the highest risk)	2