WATER | ENERGY | LIFE
CITY OF RIVERSIDE
PUBLIC UTILITIES

2023 FINANCIAL REPORT

RIVERSIDE PUBLIC UTILITIES

OVERVIEW

Riverside Public Utilities generates, transmits and distributes electricity to a 81.5-square-mile territory that includes the City of Riverside. We also deliver water to a 74.2-square-mile territory covering the majority of the City of Riverside.

The Board of Public Utilities is comprised of nine volunteers who live in all seven wards of the City of Riverside. They are appointed by the City Council to four-year terms without compensation. Board members oversee Riverside Public Utilities' policies, operations, revenues, expenditures, planning, and regulatory compliance. They provide an ongoing, year-round review of all actions by Riverside Public Utilities before any measure is sent to the elected City Council representatives for final determination.

SERVICE AREA POPULATION

313,676

RECORD PEAK DEMAND

Energy:	648 megawatts
	9/7/2022
Water:	365 acre feet
	119 million gallons
	8/9/2005

TOTAL OPERATING REVENUE

Energy:	$418.9 million
Water:	$78.7 million

CUSTOMERS

Energy:	112,751
Water:	66,441

CREDIT RATING

Energy:	AA-	Fitch
	AA-	S&P Global
Water:	AA+	Fitch
	AA+	S&P Global
	Aa2	Moody's

WATER | ENERGY | LIFE

CITY OF RIVERSIDE

PUBLIC UTILITIES

RiversidePublicUtilities.com

OUR MISSION

The City of Riverside Public Utilities Department is committed to the highest quality water and electric services at the lowest possible rates to benefit the community.

OUR VISION

Our customers will recognize Riverside Public Utilities as a unique community asset with a global reputation for innovation, sustainability and an enhanced quality of life.

OUR CORE VALUES

- Safety
- Honesty and Integrity
- Teamwork
- Professionalism
- Quality Service
- Creativity and Innovation
- Community Involvement
- Environmental Stewardship
- Inclusiveness and Mutual Respect

OUR FOCUS AREAS

RELIABILITY & RESILIENCY
Taking care of our infrastructure, so that it remains safe, and efficient.

AFFORDABILITY
Thriving financially while balancing affordable rates for our customers.

SUSTAINABILITY
Ensuring adequate power and water supply in the most environmentally responsible manner.

CUSTOMER EXPERIENCE
Continuing to provide reliable customer-centered service every day.

OPERATIONAL EXCELLENCE
Implementing new technologies that will enhance the customer experience and ensure the tradition of operational excellence.

STRONG WORKFORCE
Developing and supporting a workforce that is safe, prepared and engaged.

CROSS-CUTTING THREADS

Community Trust – Riverside is transparent and makes decisions based on sound policy, inclusive community engagement, involvement of City Boards & Commissions, and timely and reliable information. Activities and actions by the City serve the public interest, benefit the City's diverse populations, and result in greater public good.

Equity – Riverside is supportive of the City's racial, ethnic, religious, sexual orientation, identity, geographic, and other attributes of diversity and is committed to advancing the fairness of treatment, recognition of rights, and equitable distribution of services to ensure every member of the community has equal access to share in the benefits of community progress.

Fiscal Responsibility – Riverside is a prudent steward of public funds and ensures responsible management of the City's financial resources while providing quality public services to all.

Innovation – Riverside is inventive and timely in meeting the community's changing needs and prepares for the future through collaborative partnerships and adaptive processes.

Sustainability and Resiliency – Riverside is committed to meeting the needs of the present without compromising the needs of the future and ensuring the City's capacity to persevere, adapt and grow during good and difficult times alike.

Per the Operational Workplan, Riverside Public Utilities will carry out Actions to implement the City Council's Strategic Priorities and Goals below.

Community Well-Being

Ensure safe and inclusive neighborhoods where everyone can thrive.

Goal 2.3.	Strengthen neighborhood identities and improve community health and the physical environment through amenities and programs that foster an increased sense of community and enhanced feelings of pride and belonging citywide.
Goal 2.6.	Strengthen community preparedness for emergencies to ensure effective response and recovery.

Economic Opportunity

Champion a thriving, enduring economy that provides opportunity for all.

Goal 3.3.	Cultivate a business climate that welcomes innovation, entrepreneurship and investment.

Environmental Stewardship

Champion proactive and equitable climate solutions based in science to ensure clean air, safe water, a vibrant natural world, and a resilient green new economy for current and future generations.

Goal 4.1.	Rapidly decrease Riverside's carbon footprint by acting urgently to reach a zero-carbon electric grid with the goal of reaching 100% zero-carbon electricity production by 2040 while continuing to ensure safe, reliable and affordable energy for all residents.
Goal 4.2.	Sustainably manage local water resources to maximize reliability and advance water reuse to ensure safe, reliable and affordable water to our community.
Goal 4.3	Implement local and support regional proactive policies and inclusive decision-making processes to deliver environmental justice and ensure that all residents breath healthy and clean air with the goal of having zero days of unhealthy air quality per the South Coast Air Quality District's Air Quality Index (AQI).
Goal 4.5.	Maintain and conserve 30% of Riverside's natural lands in green space including, but not limited to, agricultural lands and urban forests in order to protect and restore Riverside's rich biodiversity and accelerate the natural removal of carbon, furthering our community's climate resilience.
Goal 4.6.	Implement the requisite measures to achieve citywide carbon neutrality no later than 2040.

Infrastructure, Mobility & Connectivity

Ensure safe, reliable infrastructure that benefits the community and facilitates connection between people, place and information.

Goal 6.1.	Provide, expand and ensure equitable access to sustainable modes of transportation that connect people to opportunities such as employment, education, healthcare and community amenities.
Goal 6.2.	Maintain, protect and improve assets and infrastructure within the City's built environment to ensure and enhance reliability, resiliency, sustainability and facilitate connectivity.
Goal 6.3.	Identify and pursue new and unique funding opportunities to develop, operate, maintain and renew infrastructure and programs that meet the community's needs.
Goal 6.4.	Incorporate Smart City strategies into the planning and development of local infrastructure projects.

CITY COUNCIL

Patricia Lock Dawson
Mayor

Erin Edwards
Ward 1

Clarissa Cervantes
Ward 2

Ronaldo Fierro
Ward 3

Chuck Conder
Ward 4

Gaby Plascencia
Ward 5

Jim Perry
Ward 6

Steve Hemenway
Ward 7

BOARD OF PUBLIC UTILITIES

Gil Oceguera
(Board Chair)
Ward 7

Rebeccah A. Goldware
(Board Vice Chair)
Ward 2

David M. Crohn
Ward 1

Nipunjeet Gujral
Ward 3

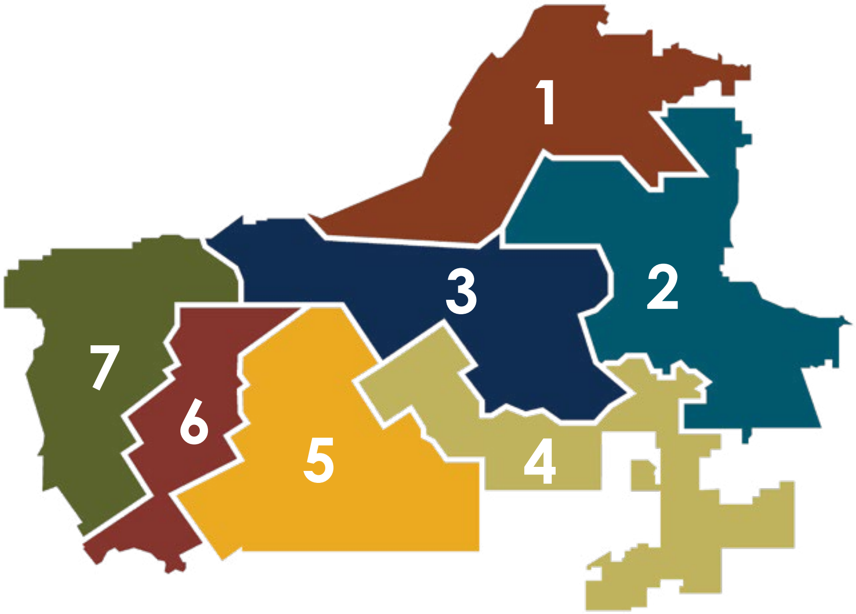
Gary Montgomery
Ward 4

Nancy E. Melendez
Ward 5

Rosemary Heru
Ward 6

Peter Wohlgemuth
Citywide / Ward 1

Brian D. Siana
Citywide / Ward 2



EXECUTIVE MANAGEMENT

Mike Futrell
City Manager

Rafael Guzman
Assistant City Manager

Todd Corbin
Utilities General Manager

Daniel E. Garcia
Utilities Deputy General Manager

Carlie Myers
Utilities Assistant General Manager
Business Systems and Customer Service

Daniel Honeyfield
Utilities Assistant General Manager
Energy Delivery

David A. Garcia
Utilities Assistant General Manager
Water Delivery

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OUR ELECTRIC

RIVERSIDE PUBLIC UTILITIES

INDEPENDENT AUDITORS' REPORT

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

Report on the Audit of the Financial Statements

Opinion

We have audited the accompanying financial statements of the Electric Utility Enterprise Fund (Electric Utility) of the City of Riverside, California, (the City) as of and for the years ended June 30, 2023, and the related notes to the financial statements, which collectively comprise the Electric Utility's financial statements as listed in the table of contents.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Electric Utility Enterprise Fund of the City of Riverside, as of June 30, 2023, and the respective changes in financial position and cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Basis for Opinion

We conducted our audit 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. Our responsibilities under those standards are further described in the Auditor's Responsibilities for the Audit of the Financial Statements section of our report. We are required to be independent of the Electric Utility and to meet our other ethical responsibilities, in accordance with the relevant ethical requirements relating to our audit. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinions.

Emphasis of Matter

As discussed in Note 1, the financial statements present only the Electric Utility Enterprise Fund of the City of Riverside and do not purport to, and do not present fairly the financial position of the City as of June 30, 2023, the changes in its financial position, or, where applicable, its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America. Our opinion is not modified with respect to this matter.

Change in Accounting Principle

As described in Note 1 to the financial statements, in the fiscal year ended June 30, 2023, the Electric Utility adopted new accounting guidance, GASB Statement No. 96, *Subscription-Based Information Technology Arrangements*. Our opinion is not modified with respect to this matter.

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

Responsibilities of Management for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with accounting principles generally accepted in the United States of America, and for the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is required to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the Electric Utility's ability to continue as a going concern for twelve months beyond the financial statement date, including any currently known information that may raise substantial doubt shortly thereafter.

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinions. Reasonable assurance is a high level of assurance but is not absolute assurance and therefore is not a guarantee that an audit conducted in accordance with generally accepted auditing standards and *Government Auditing Standards* will always detect a material misstatement when it exists. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control. Misstatements are considered material if there is a substantial likelihood that, individually or in the aggregate, they would influence the judgment made by a reasonable user based on the financial statements.

In performing an audit in accordance with generally accepted auditing standards and *Government Auditing Standards*, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Electric Utility's internal control. Accordingly, no such opinion is expressed.

- Evaluate the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluate the overall presentation of the financial statements.

We are required to communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit, significant audit findings, and certain internal control-related matters that we identified during the audit.

Required Supplementary Information

Accounting principles generally accepted in the United States of America require that the management's discussion and analysis as listed on the table of contents, presented to supplement the basic financial statements. Such information is the responsibility of management and, although not a part of the basic financial statements, is required by the Governmental Accounting Standards Board who considers it to be an essential part of financial reporting for placing the basic financial statements in an appropriate operational, economic, or historical context. We have applied certain limited procedures to the required supplementary information in accordance with auditing standards generally accepted in the United States of America, which consisted of inquiries of management about the methods of preparing the information and comparing the information for consistency with management's responses to our

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

inquiries, the basic financial statements, and other knowledge we obtained during our audit of the basic financial statements. We do not express an opinion or provide any assurance on the information because the limited procedures do not provide us with sufficient evidence to express an opinion or provide any assurance.

Summarized Comparative Information

We have previously audited the financial statements of the Electric Utility for the year ended June 30, 2022, and expressed an unmodified audit opinion on those financial statements in our report dated January 26, 2023. In our opinion, the summarized comparative information presented herein as of and for the year ended June 30, 2022 is consistent, in all material respects, with the audited financial statements from which it has been derived.

Other Information

Management is responsible for the other information included in the annual report. The other information comprises the statistical section but does not include the basic financial statements and our auditor's report thereon. Our opinions on the financial statements does not cover the other information, and we do not express an opinion or any form of assurance thereon.

In connection with our audit of the financial statements, our responsibility is to read the other information and consider whether a material inconsistency exists between the other information and the financial statements, or the other information otherwise appears to be materially misstated. If, based on the work performed, we conclude that an uncorrected material misstatement of the other information exists, we are required to describe it in our report.

Other Reporting Required by *Government Auditing Standards*

In accordance with *Government Auditing Standards*, we have also issued our report dated November 8, 2023, on our consideration of the City's internal control over financial reporting and on our tests of its compliance with certain provisions of laws, regulations, contracts, and grant agreements and other matters. The purpose of that report is solely 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 effectiveness of the City's internal control over financial reporting or on compliance. That report is an integral part of an audit performed in accordance with *Government Auditing Standards* in considering the City's internal control over financial reporting and compliance.

Lance, Soll & Lunghard, LLP

Brea, California
November 8, 2023

ELECTRIC UTILITY:
MANAGEMENT'S DISCUSSION AND ANALYSIS

As management of Riverside Public Utilities, a department of the City of Riverside (the City), we offer the readers this narrative overview and analysis of the 2022/23 financial report for the periods ended June 30, 2023 and 2022 for Riverside's Electric Utility (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 30 of this report. All amounts, unless otherwise indicated, are expressed in thousands of dollars.

FINANCIAL HIGHLIGHTS

- Governmental Accounting Standards Board No. 96, *Subscription-Based Information Technology Arrangements* (GASB 96) - For the year ended June 30, 2023, the financial statements include the adoption of GASB Statement No. 96, *Subscription-Based Information Technology Arrangements* (SBITA). This Statement defines SBITA as a contract that conveys control of the right to use another party's information technology software, alone or in a combination with tangible capital assets, as specified in a contract for a period of time in an exchange or exchange-like transaction. For additional information, refer to Notes 1, 3, and 14 in the accompanying financial statements.
- Retail sales, net of uncollectibles/recovery were $347,016 and $338,558 for years ended June 30, 2023 and 2022, respectively. The increase in sales was primarily due to rate plan increases, as well as decreased uncollectibles.
- Operating expense related to production and purchased power increased by $19,319 primarily due to a combination of exceptionally elevated winter natural gas prices and elevated power prices, along with global market disturbances.
- Operating expense reflects a non-cash pension accounting standard adjustment, which will continue to fluctuate based on yearly actuarial information provided by the California Public Employees' Retirement System. The adjustment was $(1,308) and $(16,425) at June 30, 2023 and 2022, respectively.
- Utility plant assets decreased by $10,906 primarily due to an increase in current year depreciation, offset by additions and improvements to the Electric distribution infrastructure system to improve service and reliability to the Electric Utility's customers.
- Investment income on investments increased by $16,282 due to a fair market value adjustment of investments and a higher overall interest rate in the current fiscal year.

OVERVIEW OF THE FINANCIAL STATEMENTS

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

The 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 activities, 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 ***Statements of Net Position*** present information on all of the Electric Utility's assets, liabilities, deferred inflows and outflows of resources and net position. The Statements of Net Position provide information about the nature and amount of the Electric Utility's resources and obligations at a specific point in time.

The ***Statements of Revenues, Expenses and Changes in Net Position*** report all of the Electric Utility's revenues and expenses for the periods shown.

The ***Statements of Cash Flows*** report the cash provided and used by operating activities, as well as other cash sources, such as investment income and debt financing. They also report other cash uses such as payments for bond principal and capital additions and improvements.

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 35 to 75 of this report.

ELECTRIC UTILITY FINANCIAL ANALYSIS

CONDENSED STATEMENTS OF NET POSITION

	2023	2022	2021
Current and other assets	$ 454,579	$ 501,765	$ 483,635
Capital assets	785,321	796,227	797,902
Deferred outflows of resources	45,624	24,943	42,782
Total assets and deferred outflows of resources	1,285,524	1,322,935	1,324,319
Long-term debt outstanding	590,602	615,834	639,791
Other liabilities	174,333	148,059	184,848
Deferred inflows of resources	17,237	53,479	2,307
Total liabilities and deferred inflows of resources	782,172	817,372	826,946
Net investment in capital assets	254,990	246,698	237,968
Restricted	74,163	64,422	57,884
Unrestricted	174,199	194,443	201,521
Total net position	$ 503,352	$ 505,563	$ 497,373

ASSETS AND DEFERRED OUTFLOWS OF RESOURCES

2023 compared to 2022 The Electric Utility's total assets and deferred outflows of resources were $1,285,524, reflecting a decrease of $37,411 (2.8%), primarily due to the following:

- Current and other assets, comprised of restricted and unrestricted assets, had a net decrease of $47,186, primarily due to a decrease of $12,833 in accounts receivable primarily due to renewed collection efforts post COVID-19, the decrease of $26,341 in unrestricted cash and cash equivalents primarily due to the funding of capital projects, and the transition of the net pension asset created as a result of GASB 68 to a net pension liability. The net decrease was offset by an increase of $10,388 in restricted cash and cash equivalents held by the City and ongoing operating expenditures.

- Capital assets decreased by $10,906 primarily due to current year depreciation of $28,970 offset by an increase of $18,150 in additions and improvements to the Electric distribution infrastructure system to improve service and reliability to the Electric Utility's customers. Additional capital asset information can be found in the "Capital Assets and Debt Administration" section.

- Deferred outflows of resources increased by $20,681 primarily due to an increase of $25,763 in deferred outflows related to pension, offset by the change of $4,353 in the fair market value of interest rate swaps. Additional information can be found in the "Interest Rate Swaps on Revenue Bonds" section of Note 4 Long-term Obligation.

2022 compared to 2021 Total assets and deferred outflows of resources were $1,322,935, a net decrease of $1,384 (0.1%). Current and other assets had a net increase of $18,130, primarily due to an increase of $6,639 in restricted cash and cash equivalents held by the City, an increase of $6,308 in accounts receivable primarily due to COVID-19 impacts, the net pension asset created as a result of GASB 68, and the long-term and short-term receivables created as a result of GASB 87. The net increase was offset by a decrease of $13,122 in unrestricted cash and cash equivalents, and the use of $7,473 in restricted bond proceeds to fund capital projects. Capital assets decreased by $1,675 primarily due to current year depreciation of $32,378, offset by an increase of $30,212 in additions and improvements to the Electric distribution infrastructure system to improve service and reliability to the Electric Utility's customers, as well as $628 in right-to-use lease assets offset by amortization of $137. Deferred outflows of resources decreased by $17,839 primarily due to a decrease in the fair market value of interest rate swaps.

LIABILITIES AND DEFERRED INFLOWS OF RESOURCES

2023 compared to 2022 The Electric Utility's total liabilities and deferred inflows of resources were $782,172, a decrease of $35,200 (4.3%), due to the following:

- Long-term debt outstanding decreased by $25,232 primarily due to revenue bond and pension obligation bond principal payments. Additional debt information can be found in the "Capital Assets and Debt Administration" section.
- Other liabilities increased by $26,274 primarily due to an increase of $38,748 in net pension liability. The increase was offset by decreases of $4,808 due to the change in the fair market value of interest rate swaps, as well as $4,437 in nuclear decommissioning liability, $2,687 in accounts payable, and $1,098 in unearned revenue. Additional nuclear decommissioning information can be found in Notes 10 and 13.
- Deferred inflows of resources decreased by $36,242 primarily due to pension related adjustments, which included the changes in assumptions, the differences between expected and actual experience and the change in projected versus actual earnings on pension plan investments as determined by the plan actuary. The decrease was offset by an increase in the deferred inflows related to the leases. Additional information can be found in Note 14.

2022 compared to 2021 Total liabilities and deferred inflows of resources were $817,372, a decrease of $9,574 (1.2%). Long-term debt outstanding decreased by $23,957 primarily due to revenue bond and pension obligation bond principal payments. Other liabilities decreased by $36,789 primarily due to a decrease of $39,233 in net pension liability, and a decrease of $11,063 due to a decrease in the fair market value of interest rate swaps. Deferred inflows of resources increased by $51,172 primarily due to pension related adjustments, which included the changes in assumptions, the differences between expected and actual experience, and the change in projected versus actual earnings on pension plan investments as determined by the plan actuary, as well as the creation of the deferred inflows related to leases as a result of GASB 87.

NET POSITION

2023 compared to 2022 The Electric Utility's net position, which represents the difference between the Electric Utility's total assets and deferred outflows of resources less total liabilities and deferred inflows of resources, totaled $503,352, a decrease of $2,211 (0.4%). The following represents the changes in components of net position:

- The largest portion of the Electric Utility's total net position, $254,990 (50.7%), an increase of $8,292, reflects its net investment in capital assets. Additional capital asset information can be found in the "Capital Assets and Debt Administration" section.
- The restricted portion of net position totaled $74,163 (14.7%), an increase of $9,741, and represents resources that are subject to external restrictions on how they may be used. These are reserved for items such as debt payments, Public Benefit Programs, and other legally restricted assets.
- The unrestricted portion of net position totaled $174,199 (34.6%), a decrease of $20,244 from prior year, which is primarily attributable to a decrease in operating income mainly as a result of higher power costs and the use of reserves to fund ongoing capital projects and decommissioning trusts, offset by an increase in investment income. Unrestricted net position may be used to meet the Electric Utility's ongoing operational needs and obligations to customers and creditors.

2022 compared to 2021 Total net position increased by $8,190 (1.7%), to a total of $505,563. The largest portion of the Electric Utility's total net position, $246,698, reflects its investment in capital assets less any related outstanding debt used to acquire those assets. The restricted portion of net position totaled $64,422 and represents resources that are subject to external restrictions on how they may be used. These are reserved for items such as debt payments, Public Benefit Programs, and other legally restricted assets. The unrestricted portion of net position totaled $194,443, a decrease of $7,078 from prior year, which is primarily attributable to a reduction of $10,826 in investment income, offset by an increase of $2,608 in capital contributions. Unrestricted net position may be used to meet the Electric Utility's ongoing operational needs and obligations to customers and creditors.

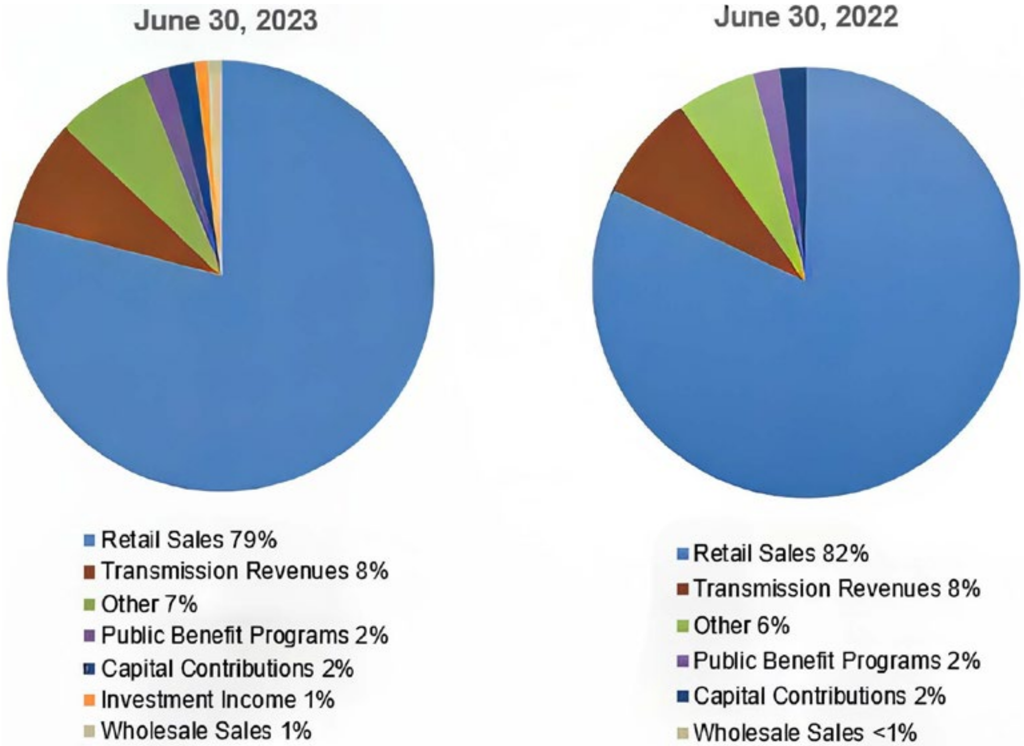
ELECTRIC UTILITY:
MANAGEMENT'S DISCUSSION AND ANALYSIS

CONDENSED STATEMENTS OF CHANGES IN NET POSITION

	2023	2022	2021
Revenues:			
Retail sales, net	$ 347,016	$ 338,558	$ 318,373
Wholesale sales	2,043	89	27
Transmission revenue	35,233	32,245	32,316
Investment income	5,952	-	496
Other revenues	30,747	25,852	18,995
Public Benefit Programs	10,222	8,978	9,252
Capital contributions	9,854	7,667	5,059
Total revenues	441,067	413,389	384,518
Expenses:			
Production and purchased power	195,914	176,595	163,908
Transmission	68,052	65,996	59,770
Distribution	68,057	39,738	70,479
Public Benefit Programs	6,751	5,467	6,419
Depreciation	38,189	36,718	35,654
Amortization	214	134	-
Loss on Investments	-	10,330	-
Interest expenses and fiscal charges	23,775	25,037	25,901
Total expenses	400,952	360,015	362,131
Transfers to the City's general fund	(42,326)	(39,436)	(39,899)
Extraordinary item	-	(5,748)	-
Changes in net position	(2,211)	8,190	(17,512)
Net position, July 1, as previously reported	505,563	497,373	514,885
Net position, June 30	$ 503,352	$ 505,563	$ 497,373

ELECTRIC UTILITY:
MANAGEMENT'S DISCUSSION AND ANALYSIS

REVENUES BY SOURCES



2023 compared to 2022 The Electric Utility’s total revenues of $441,067 increased by $27,678 (6.7%) with changes in the following:

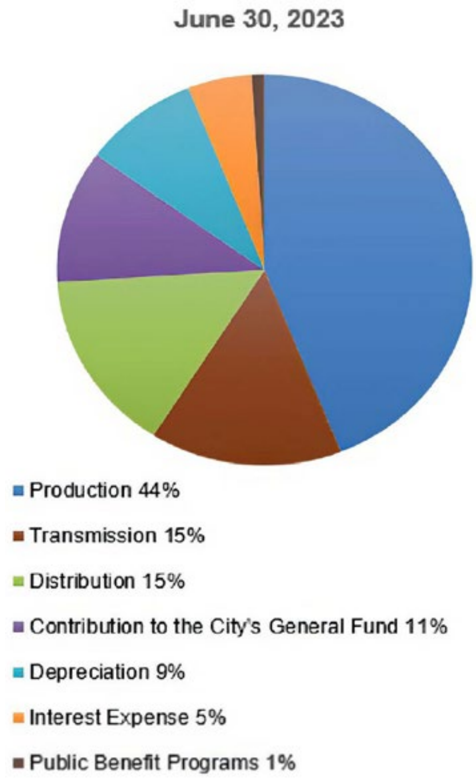
- Retail sales (residential, commercial, industrial, and others), net of uncollectibles/recovery, totaled $347,016, a $8,458 (2.5%) increase. Retail sales continue to be the primary revenue source for the Electric Utility. The increase in sales was primarily due to rate plan increases, as well as decreased uncollectibles.
- Transmission revenues of $35,233 increased by $2,988 (9.3%) primarily due to an increase in the load requirements and an increase in the average Transmission Revenue Requirement rate of $2.66 per megawatt hour.
- Other revenues of $30,747 increased by $4,895 (18.9%), primarily due to increases in greenhouse gas cap-and-trade auction proceeds.

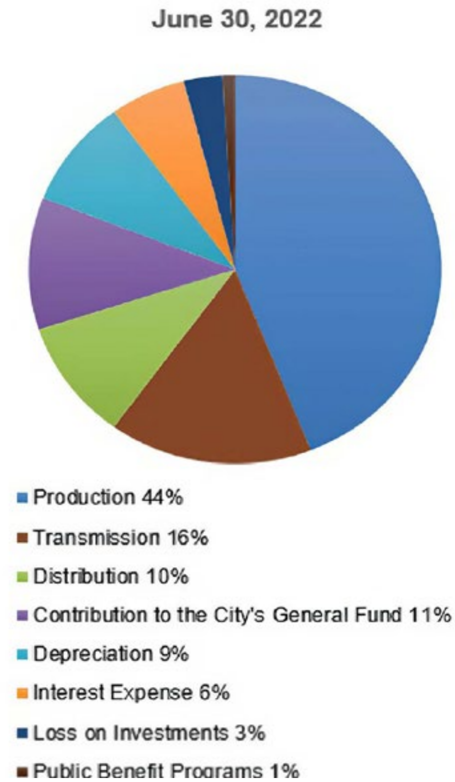
2022 compared to 2021 The Electric Utility’s total revenues of $413,389 increased by $28,871 (7.5%) with changes in the following:

- Retail sales (residential, commercial, industrial, and others), net of uncollectibles/recovery, totaled $338,558, a $20,185 (6.3%) increase. Retail sales continue to be the primary revenue source for the Electric Utility. The increase in sales was primarily due to rate plan increases, as well as decreased uncollectibles.
- Other revenues of $25,852 increased by $6,857 (36.1%) primarily due to an increase in cap-and-trade auction proceeds.
- Capital contributions of $7,667 increased by $2,608 (51.6%) mainly due to an increase in donated underground electrical conduit.

ELECTRIC UTILITY:
MANAGEMENT'S DISCUSSION AND ANALYSIS

EXPENSES BY SOURCES





2023 compared to 2022 The Electric Utility's total expenses, excluding general fund transfer, were $400,952, an increase of $40,937 (11.4%). The increase was primarily due to the following:

- Production and purchased power expenses of $195,914 increased by $19,319 (10.9%) primarily due to a combination of exceptionally elevated winter natural gas prices and elevated power prices, along with global market disturbances.
- Transmission expenses of $68,052 increased by $2,056 (3.1%) mainly due to an increase in Southern California Edison's high voltage rate and an increase in the transmission access charge from the California Independent System Operator (CAISO).
- Distribution expenses of $68,057 increased by $28,319 (71.3%), mainly due to a non-cash pension adjustment of $(1,308) compared to prior year of $(16,425) as a result of pension accounting standards, along with increases in administrative and general operating expenses.
- Depreciation expense of $38,189 increased by $1,471 (4.0%), reflecting the completion of capital projects and their current year depreciation.

2022 compared to 2021 The Electric Utility's total expenses, excluding general fund transfer, were $360,015, a decrease of $2,116 (0.6%). The decrease was primarily due to the following:

- Production and purchased power expenses of $176,595 increased by $12,687 (7.7%) primarily due to an increase in the cost of energy.
- Transmission expenses of $65,996 increased by $6,226 (10.4%) mainly due to an increase in Southern California Edison's high voltage rate and an increase in the transmission access charge from the California Independent System Operator (CAISO).
- Distribution expenses of $39,738 decreased by $30,741 (43.6%) mainly due to a non-cash pension adjustment of $(16,425) compared to prior year non-cash pension adjustment of $9,682 as a result of pension accounting standards.

- Depreciation expense of $36,718 increased by $1,064 (3.0%), reflecting the completion of capital projects and their current year depreciation.
- Loss on investments of $10,330 occurred due to a fair market value adjustment of investments and a lower overall interest rate in the current fiscal year.

TRANSFERS

Pursuant to the City of Riverside Charter, the Electric Utility may transfer up to 11.5 percent of prior year's gross operating revenues, including adjustments, to the City's general fund. 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. The Electric Utility transferred $42,326 and $39,436 for 2023 and 2022, respectively, based on the gross operating revenue provisions in the City's Charter. Additional information can be found in Note 12 of the accompanying financial statements.

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, intangibles, construction in progress, as well as general items such as office equipment, furniture, etc.

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

	2023	2022	2021
Utility plant			
Production	$ 136,413	$ 148,896	$ 157,370
Transmission	30,039	28,044	27,678
Distribution	408,103	407,181	404,352
General	63,030	65,032	63,689
Intangibles	8,032	10,166	8,639
Land	56,386	53,042	53,042
Intangibles, non-amortizable	10,651	10,651	10,651
Construction in progress	72,262	72,724	72,481
Total utility plant	784,916	795,736	797,902
Lease assets [1]			
Building	199	286	-
Machinery and equipment	156	205	-
Subscription-based information technology arrangements	50	-	-
Total lease assets	405	491	-
Total capital assets	$ 785,321	$ 796,227	$ 797,902

[1] GASB 87 *Leases* was implemented effective July 1, 2021. GASB 96 *Subscription-Based Information Technology Arrangements* (SBITA) was implemented effective July 1, 2022. For additional information, refer to Notes 1 and 14.

2023 compared to 2022 The Electric Utility's investment in capital assets, net of accumulated depreciation, was $785,321, a decrease of $10,906 (1.4%). The decrease resulted primarily from the current year depreciation offset by the following significant capital projects:

- $8,801 in recurring expenditures such as transformer replacements, cable replacements, and the Riverside Transmission Reliability Project for additional generation import capability for a second point of interconnection with the State's high voltage transmission grid.
- $5,957 in underground improvements, such as distribution line extensions and underground cable replacements.
- $5,560 in system automation improvements such as advanced metering infrastructure, and major streetlight projects.
- $4,903 in donated underground electrical conduit, donated street lighting, and donated land rights and easement.

2022 compared to 2021 Investment in capital assets, net of accumulated depreciation, was $796,227, a decrease of $1,675 (0.2%). The decrease resulted primarily from the current year depreciation offset by $13,970 in recurring expenditures such as transformer replacements, improvements to the city-wide communications network, distribution line extensions, major overhead/underground conversions, and the Riverside Transmission Reliability Project, $6,567 in underground improvements, $4,289 in system automation improvements, $2,222 in donated underground electrical conduit, donated street lighting, and donated land rights and easement, and $491 in lease assets as a result of the implementation of GASB 87.

Additional information regarding capital assets can be found in Notes 3 and 14 of the accompanying financial statements.

DEBT ADMINISTRATION

The following table summarizes outstanding long-term debt as of June 30:

	2023	2022	2021
Revenue bonds	$ 507,370	$ 524,130	$ 540,165
Unamortized premium	42,457	45,055	47,657
Financed purchases	-	364	909
Pension obligation bonds	63,408	67,641	70,951
Less: Current portion of outstanding debt	(22,633)	(21,356)	(19,891)
Total long-term debt	$ 590,602	$ 615,834	$ 639,791

The Electric Utility’s bond indentures require the Electric 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 2.01, 2.03, and 1.99 at June 30, 2023, 2022 and 2021, respectively. This debt is backed by the revenues of the Electric Utility. Debt service coverage ratio decreased at June 30, 2023 due to decreased net revenues compared to prior year along with an increase to principal payments on debt service. For additional information, see Note 4 of the accompanying financial statements and Key Historical Operating Data section.

2023 compared to 2022 The Electric Utility’s long-term debt decreased by $25,232 (4.1%) to $590,602 as a result of current year principal payments and amortization of bond premiums.

2022 compared to 2021 Long-term debt decreased by $23,957 (3.7%) to $615,834 as a result of current year principal payments and amortization of bond premiums.

Additional information on the Electric Utility’s long-term debt can be found in Note 4 of the accompanying financial statements.

CREDIT RATINGS

The Electric Utility maintains a credit rating of “AA-” from S&P Global Ratings (S&P) and “AA-” from Fitch Ratings (Fitch). These ratings are a result of the Electric Utility's evolving power resource portfolio, which is well positioned to meet California's increasing environmental regulations with an emphasis on renewable energy resources, stable financial performance and strong liquidity levels.

REGULATORY, LEGISLATIVE FACTORS, AND RATES

Utilities are faced with ongoing regulatory and legislative mandates enacted at the federal and state level that will have significant impact on the operations of the Electric Utility.

ASSEMBLY BILL (AB) 32 – GLOBAL WARMING SOLUTIONS ACT OF 2006

AB 32, enacted in 2006, requires that utilities in California reduce their greenhouse gas (GHG) emissions to 1990 levels by the year 2020. On September 8, 2016, the Governor of California expanded on this bill by approving Senate Bill 32 (SB 32), which requires the state board to ensure that statewide greenhouse gas emissions are reduced to 40% below the 1990 level by 2030.

AB 32 tasked the California Air Resources Board (CARB) to develop regulations for GHG, which became effective January 1, 2012. Emission compliance obligations under the cap-and-trade regulation began on January 1, 2013. The Cap-and-Trade Program (Program) was implemented in phases with the first phase starting from January 1, 2013 to December 31, 2014. This phase placed an emission cap on electricity generators, importers and large industrial sources emitting more than 25,000 metric tons of carbon dioxide-equivalent greenhouse gases per year. In 2015, the program expanded to cover emissions from transportation fuels, natural gas, propane, and other fossil fuels. Since the enactment of AB 32, the Electric Utility has actively participated with major investor-owned utilities and other publicly-owned utilities (POUs) to affect the final rules and regulations with respect to AB 32 implementation.

The Program requires electric utilities to have GHG allowances on an annual basis to offset GHG emissions associated with generating electricity. CARB will provide a free allocation of GHG allowances to each electric utility to mitigate retail rate impacts. If a utility requires additional allowances, then they must be purchased through the auction or on the secondary market to offset its associated GHG emissions. Each allowance can be used for compliance purposes in the current year or carried over for use for future year compliance. The Electric Utility's free allocation of GHG allowances is expected to be sufficient to meet the Electric Utility's direct GHG compliance obligations.

Any allowance not used for current year compliance or carried over for future use in compliance must be sold into the quarterly allowance auctions administered by CARB. Proceeds from the auctions must be used for the intended purposes as specified in AB 32, which include but are not limited to procurement of renewable resources, energy efficiency and conservation programs and measures that provide clear GHG reduction benefits. The Electric Utility is segregating the proceeds from the sales of allowances in the auctions as a restricted asset.

SENATE BILL (SB) 1368 – EMISSION PERFORMANCE STANDARD

The state legislature passed SB 1368 in 2006, which mandates that electric utilities are prohibited from making long-term financial commitments (commitments greater than five years in duration) for generating resources with capacity factors greater than 60 percent that exceed a GHG emission factor of 1,100 pounds per megawatt hour (lbs./MWh). SB 1368 essentially prohibits any long-term investments in generating resources based on coal. Thus, SB 1368 initially disproportionally impacted Southern California POU's as these utilities had heavily invested in coal technology. However, additional legislation such as SBX1-2, SB 350, SB 100, and SB 32 have now led to a gradual decrease in the generation of existing coal resources to serve load.

The City has ownership entitlement rights to 136 MW of the Intermountain Power Plant (IPP). IPP has a GHG emission factor of approximately 2,000 lbs./MWh. Therefore, under SB 1368, the City is precluded from renewing its IPP Power Purchase Contract at the end of its term in June 2027.

Going forward, SB 1368 related issues are expected to have minimal impact to the CAISO markets as the percentage of California load served by coal resources is small. However, to the extent that significant numbers of coal plants throughout the western United States (U.S.) start to retire in the next 5 to 15 years, it is possible that there can be a tightening of supply throughout the western U.S. electricity market. In turn, this can lead to higher regional costs and potentially reduced system reliability.

ASSEMBLY BILL (AB) 2514 - ENERGY STORAGE

AB 2514 "Energy Storage Systems" was signed into law on September 29, 2010. In 2012, AB 2227 amended the reporting timeline of the energy storage targets referenced in AB 2514. The law directs the governing boards of POUs to consider setting targets for energy storage procurement, but emphasizes that any such targets must be consistent with technological viability and cost effectiveness. The law's main directives for POUs and their respective deadlines are as follows: (a) to open a proceeding by March 1, 2012 to determine appropriate targets, if any, for the utility to procure viable and cost-effective energy storage systems, and (b) to adopt an energy storage system procurement target by October 1, 2014, if determined to be appropriate, to be achieved by the utility by December 31, 2016, and a 2nd target to be achieved by December 31, 2020. POUs were required to submit compliance reports to the CEC of their first adopted target by January 1, 2017.

Energy storage (ES) has been advocated as an effective means for addressing the growing operational problems of integrating intermittent renewable resources, as well as contributing to other applications on and off the grid. In general, ES is a set of technologies capable of storing previously generated electric energy and releasing that energy at a later time. Currently, the commercially available ES technologies (or soon to be available technologies) consist of pumped hydro generation, compressed air systems, batteries, and thermal ES systems.

On February 17, 2012, as per the statute, the City of Riverside's Board of Public Utilities opened a proceeding to investigate the various energy storage technologies available and determine if the City should adopt a 2016 energy storage procurement target. The City finished its investigation of energy storage pricing and benefits in September 2014 and adopted a zero-megawatt target based on the conclusion that the viable applications of energy storage technologies and solutions at the time were not cost effective and outweighed the benefits that it might provide to our electrical system. The

City had to reevaluate its assessment by October 1, 2017 and report to the CEC any modifications to its initial target resulting from this reevaluation.

On March 3, 2015, City Council approved the Ice Bear Pilot program for 5 MW. The program is intended to reduce load during peak hours by shifting load to off-peak hours, improve energy efficiency, and demonstrate the City's proactive support of the State's energy storage goals. Additionally, on July 28, 2015, the City Council approved a 20-year power purchase agreement for the City to procure renewable energy from the Antelope DSR Solar Photovoltaic Project that includes a built-in energy storage option for the buyers to exercise during the first fifteen years of operation.

On December 12, 2016, Riverside submitted its first compliance report to the CEC describing Riverside's proactive efforts in investigating viable energy storage options in the market and conducting energy storage pilot projects within the City to fulfill its first adopted target.

On September 11, 2017 and September 26, 2017, after reevaluating its assessment of the first adopted energy storage procurement target of zero megawatts, the Riverside Board and City Council, respectively, approved and adopted the second energy storage procurement target of six megawatts for submittal to the CEC.

SENATE BILL (SB) 380 – MORATORIUM ON NATURAL GAS STORAGE – ALISO CANYON

On October 23, 2015, a significant gas leak was discovered at the Aliso Canyon natural gas storage facility, which makes up 63% of total storage capacity and serves 17 gas fired power generation units. On May 10, 2016, the Governor of California signed SB 380 placing a moratorium on Aliso Canyon's natural gas storage usage until rigorous tests were performed and completed by the Division of Oil, Gas, and Geothermal Resources (DOGGR) as to which wells could continue to be in operation. This moratorium caused great concern regarding reliability in the upcoming summer and winter months. An action plan was initiated to review the summer and winter assessment. This action plan was conducted as a joint effort between the California Public Utilities Commission (CPUC), CEC, CAISO, and Los Angeles Department of Water and Power (LADWP). Although the area of study does not include nor immediately impact Riverside, it is highly plausible that the Electric Utility could still experience curtailed gas deliveries under certain adverse low-flow gas scenarios.

Beginning June 1, 2016, Southern California Gas Company (SoCalGas) implemented new Operational Flow Order (OFO) tariffs due to limitations surrounding Aliso Canyon storage injections and withdrawals. These tariff changes were put in place to reduce the probability of natural gas curtailments, which would disproportionally impact Riverside due to the requirements to operate internal natural gas generation to maintain system reliability during the summer. Also, gas curtailments during high peak days could lead to severe service curtailments throughout Riverside. Therefore, the Electric Utility immediately increased internal communication across divisions, created internal gas curtailment procedures to address this specific issue, and created revised dispatch procedures when load forecasts exceed 400 MW. These tighter OFO tariff restrictions were scheduled to conclude upon the return of Aliso Canyon to at least 450 million cubic feet per day (MMcfd) of injection capacity and 1,395 MMcfd of withdrawal capacity. Aliso Canyon had not been able to meet its injection and withdrawal targets, therefore, these tighter OFO tariff restrictions continued to remain in effect. In addition, the Electric Utility continues to communicate daily with the CAISO and SoCalGas on any changes that could impact our service territory.

On February 9, 2017, pursuant to SB 380, the CPUC opened a three-phase investigation to determine the feasibility of minimizing or eliminating the use of Aliso Canyon. On July 19, 2017, DOGGR issued a press release on their determination, in concurrence with the CPUC, that Aliso Canyon was safe to resume injections up to 28% of the facility's maximum capacity. On that same day, the CEC issued a different press release with a recommendation urging closure of Aliso Canyon in the long-term. On July 31, 2017, SoCalGas resumed injections. Effective July 23, 2019, the CPUC approved the Aliso Canyon Withdrawal Protocol, a protocol describing the process to follow before making a withdrawal from the natural gas storage facility. The protocol was developed with input from the CEC, the CAISO, and LADWP, and enables SoCalGas to withdraw from the Aliso Canyon natural gas storage facility when specific conditions are met related to Low Operational Flow Order (OFO) calculations, Southern California natural gas inventory levels, and/or emergency conditions.

Senate Bill 380 added Section 715 to the Public Utilities Code (PUC), which requires the CPUC to determine the range of Aliso Canyon inventory necessary to ensure safety, reliability, and just and reasonable rates. In the Section 715 Report, the Energy Division of the CPUC recommended that the maximum allowable Aliso Canyon inventory increase from 24.6 to 34 billion cubic feet (Bcf) for summer 2018 and going forward, due to continuing pipeline outages on the SoCalGas system. On May 27, 2020, the CPUC granted SoCalGas permission to withdraw natural gas from Aliso Canyon for cleanup purposes, and on February 8, 2021, approved withdrawals for performance flow testing. As of October 7, 2020, the final results of the 114 injection well tests are as follows: 66 wells have completed all required tests and have received final DOGGR (now the California Geologic Energy Management Division (CalGEM)) approval; 27 wells have been taken out of operation; and 21 wells have been plugged and abandoned. The CalGEM reduced the Aliso Canyon safe inventory limit from 86Bcf to 68.6Bcf.

On November 4, 2021, the CPUC voted to allow SoCalGas to increase the amount of natural gas inventory at the Aliso Canyon Natural Gas Storage Facility from 34Bcf to 41.16Bcf, to ensure SoCalGas meets minimum reliability needs. On September 23, 2022, the CPUC issued a Ruling that finds based on the investigation analysis, that the Aliso Canyon Natural Gas Storage Facility is needed to maintain the reliability of the natural-gas system and to help stabilize gas and electric rates until other resources are available to serve the Los Angeles Basin. In the same Ruling, the CPUC sought comments on a Staff Proposal presenting a framework to eliminate the need for Aliso Canyon by increasing non-gas-fired electricity generation and storage, building electrification, and energy efficiency. The proposal quantifies the current need for Aliso Canyon and estimates an annual increase of 1,084 MW of non-gas-fired electric generation capacity to reliably serve all energy demand without the use of Aliso Canyon by 2027. Because natural gas and electricity systems and demands are constantly evolving, this proposal suggests a biennial assessment where staff from the CPUC and CEC update supply and demand information and consider whether gas demand reductions are on track with proposed targets. If not, staff will consider whether those targets should be adjusted. If gas demand is declining on pace to meet or exceed targets, staff would recommend whether the maximum storage inventory at Aliso should be reduced. This process would continue every other year until Aliso Canyon is phased out.

In winter 2022-23, California and the Western U.S. experienced historically high natural gas prices due to widespread, below-normal temperatures; high natural gas consumption; pipeline constraints; reduced natural gas flows; and low storage inventories. On August 31, 2023, the CPUC approved an increase to the maximum storage level allowed at Aliso Canyon from 41.16Bcf up to the safety limit set by CalGEM of 68.6Bcf. The decision allows more natural gas to be injected and stored at Aliso Canyon to help secure energy reliability and protect against high natural gas and electric prices. The decision will not impact progress in proceeding towards phasing out the need for Aliso Canyon.

SENATE BILL (SB) 859 – “BUDGET TRAILER BILL” – BIOMASS MANDATE

In the final two days of the 2015-2016 legislative session, a “budget trailer bill” on how to spend cap-and-trade funds was amended to include a biomass procurement mandate for local publicly-owned utilities serving more than 100,000 customers. These utilities would be required to procure their pro-rata share of the statewide obligation of 125 MW based on the ratio of the utility’s peak demand to the total statewide peak demand from existing in-state bioenergy projects for at least a five-year term. On September 14, 2016, the Governor of California signed SB 859 into law.

On October 13, 2016, the CPUC adopted Resolution E-4805, which established that the POUs be allocated 29 MW of the 125 MW statewide mandate. The City determined that their obligated share would be 1.3 MW to meet the mandate. It is expected that the City’s proportion of these facilities will be counted towards the Electric Utility’s Renewable Portfolio Standard (RPS) goals.

In 2017, the affected POUs consisting of the cities of Anaheim, Los Angeles, and Riverside, Imperial Irrigation District, Modesto Irrigation District, Sacramento Municipal Utility District, and Turlock Irrigation District decided it would be beneficial to procure a contract together for economies of scale. This was accomplished by utilizing SCPPA to issue a Request for Proposal on behalf of all the affected POUs, since four of the seven POUs affected are existing SCPPA members.

In January 2018, the Riverside Board and City Council approved the City’s five-year Power Sales Agreement with SCPPA for 0.8 MW from the ARP-Loyalton biomass project. On April 20, 2018, the facility declared commercial operation.

On September 21, 2018, the Governor signed into law SB 901, which primarily focuses on strengthening California’s ability to prevent and recover from catastrophic wildfires such as via forest management activities, updating requirements for maintenance and operations of utility infrastructure, assessing GHG emissions impact, and protecting ratepayers. The bill also included a clause for certain biomass contracts that were procured or operating in 2018 and set to expire on or before December 31, 2023 to be offered a contract extension. The Electric Utility is required to “seek to amend the contract to include, or seek approval for a new contract that includes, an expiration date 5 years later than the expiration in the contract”. Although there is no enforcement mechanism, the ARP-Loyalton biomass project meets the above criteria and feedstock requirement referenced in SB 901 and SB 859. The Electric Utility had been working with ARP-Loyalton to comply with SB 901, but production generation from the project site ceased in early January 2020. In late February 2020, ARP-Loyalton filed for Chapter 11 bankruptcy. Sale of the project was approved by the court to a new owner on April 30, 2020, but court proceedings are still ongoing to finalize terms and conditions.

On February 24, 2020 and March 17, 2020, Riverside's Board and City Council, respectively, adopted a five-year Purchase Agreement with Roseburg Forest Products Co. for 0.5 MW in capacity to fulfill the remaining MW share of the mandate. On February 16, 2021, Roseburg declared commercial operation.

SENATE BILL (SB) 350 – CLEAN ENERGY AND POLLUTION REDUCTION ACT OF 2015

SB 350, enacted in 2015, consists of a multitude of requirements to meet the Clean Energy and Pollution Reduction Act of 2015. The primary components that affect the Electric Utility are: 1) the increased mandate of the California RPS to 50% by December 31, 2030, 2) doubling of energy efficiency savings by January 1, 2030, and 3) providing for the transformation of the CAISO into a regional organization. In addition, there is a specific integrated resource planning mandate embedded in the bill that applies to the 16 POUs that have an annual electrical demand exceeding 700 GWh over a 3-year average, which includes the Electric Utility.

The bill also requires that an updated RPS Procurement Policy must be approved and adopted before January 1, 2019 and be incorporated into the Electric Utility's Integrated Resource Plan (IRP). An Updated 2018 Renewable Energy Procurement Policy was adopted by the Board and City Council on September 10, 2018 and October 9, 2018, respectively. In parallel, on or before January 1, 2019, the governing board of the Electric Utility must adopt an IRP and a process for updating the plan at least once every 5 years. The IRP must address specific topics such as energy efficiency and demand response resources, transportation electrification, GHG emissions, energy storage resources, enhanced distribution systems and demand-side management, etc. The IRP must be submitted to the CEC for review, of which the CEC will check if the statutory requirements have been met and will adopt guidelines to govern the submission of the IRP information. On August 9, 2017, the CEC adopted the POU IRP Submission and Review Guidelines.

On September 30, 2017, the Governor signed SB 338, which requires that the governing board of local POUs consider as part of the IRP process the role of existing renewable generation, grid operational efficiencies, energy storage, energy efficiency, and distributed energy resources in meeting the energy and reliability needs of each utility during the hours of peak demand. On August 1, 2018, the CEC adopted a Second Edition of the POU IRP Submission and Review Guidelines to include the requirements of SB 338. On October 3, 2018, the CEC adopted an amendment to the second edition guidelines to include the CARB's GHG emission reduction planning targets for IRPs.

On November 26, 2018 and December 11, 2018, the Board of Public Utilities and City Council, respectively, adopted the Electric Utility's 2018 Integrated Resource Plan. The IRP and additional submittal requirements were submitted to the CEC on December 18, 2018. In April 2019, the CEC issued their Staff Paper Review of the Electric Utility's IRP, as well as the CEC Executive Director's Determination Letter finding the Electric Utility to be consistent with the requirements of SB 350. The adoption of this determination occurred at the CEC Business meeting on August 14, 2019.

The CEC continues to host various workshops on different components of the SB 350 requirement and the Electric Utility has been monitoring its outcome.

ASSEMBLY BILL (AB) 1110 AND SENATE BILL (SB) 1158 - LEGISLATION RELATING TO GREENHOUSE GAS EMISSIONS REPORTING FOR POWER RESOURCE DISCLOSURE

On September 26, 2016, AB 1110 was signed into law requiring GHG emissions intensity data and unbundled renewable energy credits (RECs) to be included as part of the retail suppliers' power source disclosure (PSD) report and power content label (PCL) to their customers. GHG emissions intensity factors will need to be provided for all retail electricity products. The inclusion of this new information requirement on the PCL will begin in 2021 for calendar year 2020 data. In addition to still being required to post the PCL on the city website, the bill also reinstated the requirement that the PCL disclosures must be mailed to the customers starting in 2017 for calendar year 2016 data unless customers have opted for electronic notifications. In accordance with this requirement, Riverside reinstated the inclusion of printed disclosures of the PCL with its September 2017 bills to the customers.

In 2017, the CEC began hosting workshops on the GHG emissions disclosure requirements and initiated the rulemaking process of updating their PSD regulations. A pre-rulemaking phase also began that included an implementation proposal on AB 1110. The legislation requires the CEC to adopt guidelines by January 1, 2018. In early 2018, the CEC provided an update to their 2017 pre-rulemaking activities and proposed changes to the regulations and reports, but additional workshops were needed. In March 2019, the last pre-rulemaking workshop was held by the CEC, with the intent to begin the formal rulemaking in May, but was delayed until September 2019. On December 11, 2019, the CEC adopted the updated PSD regulations, which changed the timing of the inclusion of the GHG emissions intensity data to be included in the PCL starting in 2021 for calendar year 2020 data. The adoption of the updated PSD regulations and how the additional GHG emissions intensity information would be conveyed to customers in the PSD report and PCL was approved on May 4,

2020. The most notable changes to the report and label are the addition of the GHG emissions intensity and how certain energy resources would be conveyed to the customers to meet the AB 1110 requirement.

On September 16, 2022, Senate Bill (SB) 1158 was signed into law which requires, beginning January 1, 2028, every retail supplier to annually report to the CEC information concerning electricity supply used to serve load, including the retail supplier's hourly sources of electricity and the emissions of GHG associated with those sources of electricity. The bill also requires the CEC to share and publish the information annually on its website in an aggregated summary. The CEC is required to adopt rules to implement these reporting requirements on or before July 1, 2024. Currently the CEC is in a pre-rulemaking period but is expected to enter a formal rulemaking period in Fall 2023. Riverside continues to monitor upcoming workshops and draft regulations for any impacts to the utility’s reporting and portfolio of resources.

ASSEMBLY BILL (AB) 398 – GHG CAP-AND-TRADE PROGRAM EXTENSION

AB 398 was signed on July 25, 2017 and approved extending the GHG cap-and-trade program to December 31, 2030, which was originally implemented under AB 32. This bill was also a companion bill to AB 617 as part of a legislative package that will be discussed further below. In addition, AB 398 required the CARB to update their scoping plan no later than January 1, 2018. AB 398 also requires all adopted GHG rules and regulations to be consistent with this plan. On July 27, 2017, the CARB approved the 2016 Cap-and-Trade Amendments, which includes the Electric Utility’s 2021-2030 allowance allocations it will receive each year. The Electric Utility’s allowance allocations should be sufficient to cover all of its 2021- 2030 direct compliance obligations.

Initially, it was unclear under AB 398 whether the Electric Utility would be required to consign 100% of its allowances to the market and then purchase allowances to fulfill its compliance obligations. Since the start of the Cap-and-Trade program in 2012, POUs have been able to directly assign allowances for compliance. However, in 2017, the CARB announced they were reconsidering this provision. In early 2018, after much discussion and collaboration with the CARB in which the POUs demonstrated that they continue to include the price of GHG emissions in the cost of energy, it was agreed that the POUs would not be forced to consign their allocated direct-compliance allowances to auction. Other unknown components of the law include the banking provisions and the specific GHG revenue spending requirement for revenues generated from the sale of excess allowances.

In June 2021, the CARB began focus area discussion workshops as part of the next iteration of the Scoping Plan Update on four areas: 1) electricity sector, 2) transportation sector, 3) equity and environmental justice, and 4) natural and working lands. On June 8, 2021, the CARB hosted a workshop series to commence development of the 2022 Scoping Plan Update to Achieve Carbon Neutrality by 2045. Starting in July 2021 and onward, a series of technical workshops were hosted to cover various topics and sectors within the Scoping Plan. On December 15, 2022, the CARB Board unanimously adopted the 2022 Scoping Plan Update. The Scoping Plan focuses on laying out the path to achieving carbon neutrality and reducing anthropogenic GHG emissions by 85 percent below 1990 levels no later than 2045. The 2022 Scoping Plan includes decarbonization through the electrification of transportation and buildings which will increase the transportation and generation needs of the Electric Utility. The Scoping Plan also states that storage and demand-side management will be essential to maintaining reliability as more renewables are incorporated into the electric grid.

On July 27, 2023, the CARB held a workshop on the potential amendments to the cap-and-trade regulation. The CARB is again proposing the requirement for consignment of POU allocations, which would add significant cost uncertainty into energy pricing and require the Electric Utility to purchase allowances from auction using alternative ratepayer funds. Potential impacts also include a decrease of annual allowance allocations and impacts to the Mandatory Reporting Requirement (MRR). The CARB has shown a particular interest in ensuring that allowance value targets low-income and priority communities. It is anticipated that the formal rulemaking will begin in late 2023 or early 2024 with the goal of the new regulations becoming effective January 1, 2025. The Electric Utility will continue to monitor the outcome and impacts of the upcoming regulations on its service territory and ratepayers.

ASSEMBLY BILL (AB) 617 – AIR QUALITY MONITORING

AB 617 was signed on July 26, 2017 and was part of a legislative bill package with AB 398, which authorized the extension of the Cap-and-Trade Program in the State. AB 617 addresses the disproportionate impacts of air pollution in areas impacted by a combination of economic, health, and environmental burdens. These burdens include combinations of poverty, high unemployment, health conditions such as asthma and heart disease, air and water pollution, and hazardous wastes. Both the CARB and local air districts are required to take specific actions to reduce air pollution and toxic air contaminants from commercial and industrial sources, including from electricity-generating facilities. The bill required the CARB, by October 1, 2018, to prepare a statewide monitoring plan regarding technologies and reasons for monitoring air quality and, based on that plan, identify the highest priority locations for the deployment of community level air monitoring systems. Local air districts are required to deploy the air monitoring systems in the specified communities by July 1, 2019. Additional locations for the deployment of the systems will be identified annually by the CARB beginning January 1, 2020. The CARB is also required to provide grants to community-based organizations for technical assistance and to support community participation in the programs. In turn, this effort would require the local air district of the selected community to adopt a community emissions reduction program.

Additionally, AB 617 requires the CARB to develop uniform reporting standards for criteria air pollutants and toxic air contaminants for specific uses, including electricity-generating facilities. Air districts are to adopt an expedited schedule for implementing best available retrofit control technologies for the uses, while the CARB will identify these technologies.

This bill affects the City and the Electric Utility by imposing additional reporting requirements, particularly on power plants, and potentially adding or improving air monitoring systems in selected communities located within the City of Riverside. For Riverside, the local air district is the Southern California Air Quality Management District (“SCAQMD”). The CARB and SCAQMD have held and continue to hold community meetings to implement the required elements of AB 617. Preliminary discussions and proposals have already been conveyed by community members from the City as well as from the University of California, Riverside proposing areas for community air monitoring and planning. The City and Electric Utility are monitoring the progress of the community meetings and the two proposed areas for any impacts.

ASSEMBLY BILL (AB) 802 – BUILDING ENERGY USE BENCHMARKING AND PUBLIC DISCLOSURE PROGRAM

On October 8, 2015, AB 802 was signed into law creating a new statewide building energy use benchmarking and public disclosure program for the State of California. The bill requires California utilities to maintain records of energy usage data for all buildings (i.e., commercial and multifamily buildings over 50,000 square feet gross floor area) for at least the most recent 12 months. Beginning January 1, 2017, utilities are required to deliver or provide aggregated energy usage data for a covered building, as defined, to the owner, owner’s agent or operator upon written request. The Electric Utility provides consumption data for buildings meeting the legislative requirement upon owners’ written request. The CEC adopted regulations on October 11, 2017 and approved the regulation action to be effective on March 1, 2018. Building owners are required to report this information annually beginning on June 1, 2018.

SENATE BILL (SB) 100 – THE 100 PERCENT CLEAN ENERGY ACT OF 2018

On September 10, 2018, the Governor signed into law the 100 Percent Clean Energy Act of 2018 (SB 100). This bill further increases the RPS goals of SBX1-2 and SB 350, while maintaining the 33% RPS target by December 31, 2020, but modifying the future RPS percentages to be 44% by December 31, 2024, 52% by December 31, 2027, and 60% by December 31, 2030. The current end goal of SB 100 is to have 100% of the state's retail electricity supply generated from a mix of RPS-eligible and zero-carbon resources by December 31, 2045.

The CEC is required to establish appropriate multi-year compliance periods for all subsequent years after 2030 that will require POUs to procure not less than 60% of retail sales from renewable resources. In September 2019, the CEC began conducting pre-rulemaking workshops to discuss potential amendments to the RPS Enforcement Procedures for POUs that would incorporate the SB 100 mandates. In addition, POUs will need to include the increased requirements in their future IRP. On December 1, 2020, the CEC released the 3rd 15-day language for the RPS Enforcement Procedures for POUs and adopted it at the December 22, 2020 CEC Business Meeting. It was approved by the Office of Administrative Law (OAL) and made effective July 12, 2021. The updated procedures clarify the interim targets for each year and that compliance periods beginning on and after January 1, 2031, shall be three years in length starting on January 1 and ending on December 31. For each compliance period beginning on or after January 1, 2031, a POU shall demonstrate it has procured electricity products within the compliance period sufficient to meet or exceed an average of 60 percent of the POU's retail sales over the three calendar years of the compliance period.

On December 4, 2020, the CEC issued a draft SB 100 Joint Agency Report, presented by the CEC with the CARB and CPUC. The joint agency report is intended to inform policy and planning, which is required to be presented to the legislature every four years starting on January 1, 2021. The final report was published by the CEC and joint agencies on March 15, 2021. On August 22, 2023, the CEC, the CARB, and CPUC held a joint workshop to discuss findings and recommendations from the 2021 SB 100 Joint Agency Report and the plan to address these findings and recommendations as the 2025 SB 100 Joint Agency Report is being developed. Riverside will continue to monitor the outcome and impacts of any upcoming workshops and regulations in meeting the new requirements.

SENATE BILL (SB) 1028, SB 901 AND ASSEMBLY BILL (AB) 1054 – LEGISLATION RELATING TO WILDFIRES

On September 24, 2016, Governor Brown signed into law SB 1028, which requires each POU, IOU and electric cooperative to construct, maintain, and operate its electrical lines and equipment in a manner that will minimize the risk of catastrophic wildfire posed by those electrical lines and equipment.

SB 901, which was passed at the end of the 2017-2018 biennium session of the California State Legislature and signed by the Governor on September 21, 2018, is meant to address the Governor's and legislative leaders' desire to address response, mitigation, and prevention of wildfires. SB 901 requires the Electric Utility to prepare before January 1, 2020 and annually thereafter, a wildfire mitigation plan (WMP) that includes specified information and elements. The Electric Utility must present its WMP in an appropriately noticed public meeting and accept comments on the plan from the public, other local and state agencies, and interested parties, and to verify that the plan complies with all applicable rules, regulations, and standards, as appropriate. In addition, the Electric Utility must contract with a qualified independent evaluator to review and assess the comprehensiveness of its plan. The report of the independent evaluator must be made available on the Electric Utility's website and presented at the local governing board's public meeting.

On July 12, 2019, the Governor signed into law AB 1054 and AB 111, which establishes the California Wildfire Safety Advisory Board (WSAB), adds an additional process requirement for review of wildfire mitigation plans, and establishes a wildfire fund. In addition to the Electric Utility presenting its WMP to its local governing board by January 1, 2020, the Electric Utility must submit it to the new advisory board by July 1, 2020 and provide annual updates each year thereafter. Additionally, the Electric Utility is required to submit a comprehensive WMP at least once every three years.

The City fully complied with AB 1054 and the City Council formally adopted the Wildfire Mitigation Plan on December 17, 2019. Following City Council adoption, this approved plan was also submitted to the WSAB on May 6, 2020, as required.

On December 9, 2020, the WSAB completed their review of all publicly-owned utilities' initial WMPs and issued an advisory opinion applicable to all POUs. It identified several themes that all POUs were requested to address and were not required to incorporate the recommendations as part of the next annual WMP update. Instead, POUs were asked to respond to a matrix of questions to be submitted at the same time as the next update of the WMP. The matrix is not required to be presented to the public utilities' governing boards.

On June 14, 2021, the Electric Utility presented the updated 2021 WMP to its Board and received a recommendation that the City Council approve the 2021 Riverside Public Utilities WMP annual update for submittal to the WSAB by July 1, 2021. During the Board meeting, staff identified updates to the WMP that would allow the Electric Utility to better respond to the WSAB's advisory opinion that had not been incorporated into the WMP. Instead of bringing it before the City Council for approval as is, staff opted to remove the item from consideration in order to provide an updated 2021 Riverside Public Utilities WMP to the Riverside Board for approval again. The update to the 2021 Riverside Public Utilities WMP was approved on September 27, 2021 and October 12, 2021 by the Riverside Board and City Council, respectively.

On June 27, 2022, the Riverside Board approved the 2022 WMP which was then submitted to the WSAB on June 30, 2022. On October 17, 2022, the WSAB issued a guidance advisory opinion for the 2023 WMP for electric POUs and rural electric cooperatives. The advisory opinion included general guidance that applied to all POUs, specific guidance for each POU, and a template with instructions for preparing 2023 plans. All guidance was incorporated into Riverside's 2023 WMP. The 2023 WMP included the steps, programs, policies, and procedures implemented by the Electric Utility to reduce wildfire risks and minimize impacts to customers. As required by PUC Section 8387, a qualified independent evaluator was contracted to review and assess the 2023 WMP for comprehensiveness. The independent evaluator provided feedback on the plan, which the Electric Utility incorporated by including additional details to further clarify the Electric Utility's wildfire mitigation measures. Afterwards, the independent evaluator concluded that the Electric Utility's 2023 WMP was sufficient in meeting the requirements for comprehensiveness. On June 26, 2023 and July 18, 2023, the 2023 WMP and independent evaluator's findings were presented to the Riverside Board and City Council, respectively. The 2023 WMP was submitted to the WSAB on July 19, 2023.

For the wildfire fund, only voluntarily participating IOUs are eligible for claims arising from a covered wildfire. The POUs are not required nor able to join due to concerns and issues over complications of funding as a public entity. The bills do not address existing legal doctrine relating to utilities' liability for wildfires. However, any future legislation that addresses California's inverse condemnation and strict liability issues for utilities in the context of wildfires could be significant for the Electric Utility. Riverside is regularly engaged with the current WSAB meetings and updates, continues to partner with the Riverside Fire Department and diligently monitor the outcome and impacts of any upcoming legislation and regulations on its service territory and ratepayers.

ASSEMBLY BILL (AB) 205 – ON-CALL RESOURCES AND ENERGY STORAGE

On June 30, 2022, AB 205 was signed into law to address several energy topics but more specifically, on-call emergency supply and load reduction for the state's electrical grid during extreme events to reduce the risk of blackouts. AB 205 requires the CEC to implement and administer the Distributed Electricity Backup Assets (DEBA) Program to incentivize the construction of cleaner and more efficient distributed energy assets and the Demand Side Grid Support (DSGS) Program to incentivize dispatchable customer load reduction and backup generation operation to be on-call for extreme events.

The initial DSGS program and guidelines launched in the Summer of 2022 and concluded October 2022. On July 26, 2023 the CEC adopted the second edition of the DSGS guidelines, which made the program effective immediately. In 2023, the Electric Utility will be participating in the DSGS program utilizing the CEC's contracted administrator who will manage the direct participation of the Electric Utility's customers in the DSGS program. Through the program, participating customers receive a financial incentive for on-call load reduction during extreme events and the Electric Utility receives reimbursement for administrative costs to facilitate customer participation. The funding for the DSGS program was authorized by AB 205 and further expanded by AB 102 (signed on July 10, 2023) which stated the funding would be available for five years until June 30, 2027.

On January 27, 2023 the CEC held a workshop to discuss the DSGS program and the DEBA program. Information from this meeting was used to inform the development of the DEBA program. Proposed guidelines were released on August 11, 2023 and the CEC hosted a public workshop to solicit stakeholder feedback on the proposed guidelines on August 15, 2023. The proposed guidelines set aside 25% of program funding for projects in POU territories which would be awarded through grant funding opportunity solicitations. Payment is currently set to be disbursed beginning at the start of commercial operation and then spread over five years. Additional clarification is needed regarding whether project infrastructure costs associated with the project would be eligible for funding and if projects would be authorized to serve as a resource adequacy resource. This program could potentially provide funding to the Electric Utility for additional bulk grid assets and/or distributed resources.

The Electric Utility will continue to monitor upcoming workshops and regulations for funding opportunities and any impacts on its service territory and ratepayers.

ASSEMBLY BILL (AB) 209 – ENERGY AND CLIMATE CHANGE

On September 6, 2023, AB 209 was signed into law authorizing several energy programs to address climate change. One program is the Equitable Building Decarbonization Program. The program provides funding for a Statewide Direct Install Program, Tribal Direct Install Program, a Statewide Incentive Program, and provides support for existing programs. This program must serve under-resourced communities and can fund eligible measures such as heating and cooling, building envelope retrofits, water heating, cooking, and more. Draft guidelines were released on May 4, 2023 and final guidelines are anticipated to be adopted in Fall 2023 with the program expected to rollout to initial communities in 2024-2025.

AB 209 also established directives for allocating general funds to provide incentives for eligible residential customers, including publicly owned utility (POU) customers, for the Self-Generation Incentive Program (SGIP). SGIP provides incentives to support existing, new, and emerging distributed energy resources installed on the customer's side of the utility meter. Qualifying technologies include wind turbines, fuel cells, advanced energy storage systems and more. On July 10, 2023, the Governor approved Senate Bill (SB) 123, clarifying that SGIP incentives are eligible for low-income residential customers who install behind-the-meter energy storage or photovoltaic systems. It also clarified that these incentives are available to POU customers.

Another program under AB 209 that the CEC must establish and administer is the Hydrogen Program to provide financial incentives to in-state hydrogen projects for the demonstration or scale-up of the production, processing, delivery, storage, or end use of clean hydrogen. The CEC held a workshop in December 2022 to provide an overview of the Clean Hydrogen Program and the proposed program scope, funding areas, and project requirements. On May 19, 2023 the CEC released a draft solicitation concept for large-scale centralized production to solicit public feedback. On May 23, 2023 the CEC released the "Cost Share for Federal Clean Energy Funding Opportunities" competitive solicitation.

The Electric Utility will continue to monitor the development of these programs to determine opportunities and impacts on its service territory and ratepayers.

FIVE-YEAR ELECTRIC RATE PLAN

On May 22, 2018, the City Council approved a five-year Electric Rate Plan; the final annual rate increase of 3.0% was effective January 1, 2023 and was in effect through June 30, 2023.

ELECTRIC UTILITY:
MANAGEMENT'S DISCUSSION AND ANALYSIS

On September 19, 2023, the City Council approved a new five-year Electric Rate Plan, which includes system average annual rate increases. The first rate increase is effective January 1, 2024 with the following four years effective on January 1 of each year. The approved five-year Electric Rate Plan includes annual reviews of the adopted rates by City Council. The system average rate increases effective January 1, 2024 through 2026 are 7.0%, followed by system average rate increases of 2.0% in years four and five. The Electric Rate Plan was designed to provide financial stability and correct the imbalance of costs versus revenue recovery.

ECONOMIC DEVELOPMENT AND GREEN INITIATIVES

The City of Riverside has a long history of valuing sustainability and ensuring economic development. Recent efforts for sustainability began in 2001 when the City began using light-emitting diodes in all City traffic signals to reduce electricity usage. Today, the City remains committed to environmental issues and serves as a state leader in sustainability.

The City's first sustainability policy statement was adopted in 2007 and ultimately led to the adoption of three Green Action Plans, the most recent in 2012. Most recently, the City adopted the Envision Riverside 2025 Strategic Plan in October 2020. This plan incorporates sustainability throughout as a cross cutting value and environmental stewardship as one of six priority areas for the City. Additional adopted policies can be found in the City's General Plan 2025 (2007), the Environmentally Preferable Purchasing Policy (2009), the Food and Agriculture Policy Action Plan (2015) and the Riverside Restorative Growthprint (2016).

The City hosts community-wide Green Riverside Leadership Summits. Since 2012, summits have been held every 2 to 3 years. Events in 2012 and 2019 were in partnership with the University of California Riverside. Events in 2014 and 2016 were conducted as part of the community-led Riverside Green Festival and Summit.

The City has received numerous recognitions for its sustainability programs and initiatives. In 2009, the California Department of Conservation named Riverside its first "Emerald City" in recognition for its sustainable green initiatives and commitment to help the state achieve multiple state environmental priorities. The City was honored in 2016 with the Green Community Award from Audubon International, recognizing Riverside for its ongoing sustainability initiatives. In addition, the City received the 2016 Sustainable Communities Award from the Green California Leadership Summit for its ongoing community-wide sustainability projects and programs that create environmental awareness and action throughout the community, including business, government and private citizens. The Green California Leadership Summit again recognized the City in 2018 with its Leadership Award for the City Green Fleet Program. Additionally, in 2022, Riverside was ranked #1 in North America for the Green Fleet Award by the NAFA Fleet Management Association.

The Utility hosted its inaugural community Earth Day celebration in 2022. The day provided customers with information and tips on energy efficiency and water conservation best practices. There were electric vehicle demonstrations and experts on hand to advise on how to incorporate native plants in local landscapes. Earth Day 2023 was marked by another community celebration day, hosted in collaboration with the City's Insect Fair. This year, the RPU team was able to expand on the previous messaging and outreach at this bigger event. RPU hosted several booths and the Wyland interactive truck, which provided a hands-on experience for attendees to learn in detail about water conservation and energy efficiency, and the changes they could make towards achieving these goals.

The Electric Utility supports the local economy by offering some of the lowest commercial electric rates in Southern California combined with attractive economic development electric discount rates to qualified new and expanded load customers. These rate programs have helped create and retain over 3,600 jobs in the City since 2010. In late 2021, the Utility relaunched the commercial energy audit program, which provides Key Account customers with a comprehensive energy efficiency plan, a priority list of recommended energy efficiency measures, an estimated return on investment and applicable utility incentives. To date, several key customers have utilized this program, resulting in approximately 700,000 kWh annual savings this year. More audits are planned over the coming months.

Beyond rate incentives, the Electric Utility also offers local businesses a comprehensive assortment of water and energy efficiency programs to improve building efficiency and reduce customer electric consumption. Fiscal year 2021/22 commercial energy efficiency programs saved a total of 4.2 million kWh. Fiscal year 2022/23 saw increased energy efficiencies being realized, with almost 7.3 million kWh saved via RPU's programs.

All of these efforts support organizations and companies in meeting their sustainability goals. Most recently, the State of California's Air Resources Board relocated their Southern California headquarters to the City of Riverside. The campus opened in 2021 and is one of the largest and most advanced vehicle emissions testing and research facilities in the world. Additionally, the headquarters are LEED Platinum, the highest level awarded by the U.S. Green Building Council for the overall sustainability and energy efficiency of a building. This facility, through a combination of on-site solar PV and a 100%

renewable energy rate program through the utility, receives all of its power from non-carbon emitting resources.

The City initiated an ambitious LED streetlight replacement program in 2016. The program will eventually replace all city-owned streetlights by 2026, resulting in approximately 10 million kWh saved annually along with substantially reduced maintenance costs. Additionally, the Utility's Energy, Water and Custom Energy technology grant programs continue to encourage local higher education institutions and business electric customers to submit proposals for potential grant funding for important research projects that explore new and innovative ways to advance energy technology.

These economic development and sustainability projects and programs put the Electric Utility on the cutting edge of job creation and resource efficiency, making the City a better place to live and do business.

REQUESTS FOR INFORMATION

This financial report is designed to provide a general overview of the 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 – Business Systems and Customer Service, Riverside Public Utilities, 3750 University Avenue, 5th floor, Riverside, CA 92501. Additional financial information can also be obtained by visiting www.RiversidePublicUtilities.com.

ELECTRIC UTILITY:
FINANCIAL STATEMENTS

STATEMENTS OF NET POSITION

ASSETS AND DEFERRED OUTFLOWS OF RESOURCES	June 30, 2023 (in thousands)	June 30, 2022
NON-CURRENT ASSETS:		
Capital assets:		
Utility plant, net of accumulated depreciation (Note 3)	$ 784,916	$ 795,736
Lease and subscription assets, net of amortization (Note 3)	405	491
Total capital assets	785,321	796,227
Restricted assets:		
Cash and investments at fiscal agent (Note 2)	58,135	53,785
Total non-current restricted assets	58,135	53,785
Other non-current assets:		
Advances to other funds of the City	2,003	2,454
Lease receivable (Note 14)	10,407	7,099
Unamortized purchase power (Note 11)	11,664	12,317
Regulatory assets	1,573	1,665
Net pension asset (Note 6)	-	26,219
Total other non-current assets	25,647	49,754
Total non-current assets	869,103	899,766
CURRENT ASSETS:		
Unrestricted assets:		
Cash and cash equivalents (Note 2)	247,831	274,172
Accounts receivable, less allowance for doubtful accounts 2023 ($3,351); 2022 ($2,996)	37,260	50,093
Accrued interest receivable	1,033	663
Leases receivable (Note 14)	1,359	990
Inventory	1,464	485
Prepaid expenses	6,168	6,127
Unamortized purchase power (Note 11)	666	653
Total unrestricted current assets	295,781	333,183
Restricted assets:		
Cash and cash equivalents (Note 2)	44,794	38,526
Public Benefit Programs - cash and cash equivalents (Note 2)	29,152	25,032
Public Benefit Programs receivable	1,070	1,485
Total restricted current assets	75,016	65,043
Total current assets:	370,797	398,226
Total assets	1,239,900	1,297,992
DEFERRED OUTFLOWS OF RESOURCES:		
Deferred outflows related to pension (Note 6)	34,931	9,168
Deferred outflows related to other postemployment benefits (Note 7)	1,592	1,805
Changes in derivative values	1,571	5,924
Loss on refunding	7,530	8,046
Total deferred outflows of resources	45,624	24,943
Total assets and deferred outflows of resources	$ 1,285,524	$ 1,322,935

See accompanying notes to financial statements

ELECTRIC UTILITY:
FINANCIAL STATEMENTS

STATEMENTS OF NET POSITION

NET POSITION, LIABILITIES AND DEFERRED INFLOWS OF RESOURCES	June 30, 2023 (in thousands)	June 30, 2022
NET POSITION:		
Net investment in capital assets	$ 254,990	$ 246,698
Restricted for:		
Regulatory requirements(Note 8)	25,502	19,598
Debt service (Note 8)	19,332	18,967
Public Benefit Programs	29,329	25,857
Unrestricted	174,199	194,443
Total net position	503,352	505,563
LONG-TERM OBLIGATIONS, LESS CURRENT PORTION (Note 4)	590,602	615,834
OTHER NON-CURRENT LIABILITIES:		
Compensated absences (Note 5)	1,889	2,426
Net pension liability (Note 6)	38,748	-
Nuclear decommissioning liability (Note 10)	38,646	44,497
Other postemployment benefits liability (Note 7)	9,420	10,066
Derivative instruments (Note 4)	4,097	8,905
Regulatory liability	4,675	4,220
Lease liability (Note 14)	225	363
SBITA liability (Note 14)	7	-
Total other non-current liabilities	97,707	70,477
CURRENT LIABILITIES PAYABLE FROM RESTRICTED ASSETS:		
Accrued interest	5,083	5,465
Public Benefit Programs payable	866	624
Nuclear decommissioning liability (Note 10)	10,227	8,813
Current portion of long-term obligations (Note 4)	22,633	20,992
Total current liabilities payable from restricted assets	38,809	35,894
CURRENT LIABILITIES:		
Accounts payable and other accruals	19,584	22,722
Compensated absences (Note 5)	5,589	4,774
Customer deposits	11,734	11,888
Unearned revenue	314	1,412
Other postemployment benefits liability (Note 7)	417	394
Current portion of long-term obligations (Note 4)	-	364
Lease liability (Note 14)	137	134
SBITA liability (Note 14)	42	-
Total current liabilities	37,817	41,688
Total liabilities	764,935	763,893
DEFERRED INFLOWS OF RESOURCES:		
Deferred inflows related to pension (Note 6)	3,577	44,089
Deferred inflows related to other postemployment benefits (Note 7)	2,266	1,426
Lease related items (Note 14)	11,394	7,964
Total deferred inflows of resources	17,237	53,479
Total net position, liabilities and deferred inflows of resources	$ 1,285,524	$ 1,322,935

See accompanying notes to financial statements

ELECTRIC UTILITY:
FINANCIAL STATEMENTS

STATEMENTS OF REVENUES, EXPENSES AND CHANGES IN NET POSITION

	For the Fiscal Years Ended June 30, 2023 (in thousands)	2022
OPERATING REVENUES:		
Residential sales	$ 140,538	$ 134,403
Commercial sales	77,191	75,899
Industrial sales	124,600	122,684
Other sales	5,162	4,891
Wholesale sales	2,043	89
Transmission revenue	35,233	32,245
Other operating revenue	24,403	18,758
Public Benefit Programs	10,222	8,978
Total operating revenues before uncollectibles	419,392	397,947
Estimated uncollectibles, net of bad debt recovery	(475)	681
Total operating revenues, net of uncollectibles	418,917	398,628
OPERATING EXPENSES:		
Production and purchased power	195,914	176,595
Transmission	68,052	65,996
Distribution	68,057	39,738
Public Benefit Programs	6,751	5,467
Depreciation	38,189	36,718
Amortization	214	134
Total operating expenses	377,177	324,648
Operating income	41,740	73,980
NON-OPERATING REVENUES (EXPENSES):		
Investment (loss) income	5,952	(10,330)
Interest expense and fiscal charges	(23,775)	(25,037)
Gain on sale of assets	957	505
Other	5,387	6,589
Total non-operating revenues (expenses)	(11,479)	(28,273)
Income before capital contributions and operating transfers out	30,261	45,707
Capital contributions	9,854	7,667
Transfers out - contributions to the City's general fund	(42,326)	(39,436)
Total capital contributions and transfers out	(32,472)	(31,769)
EXTRAORDINARY ITEM (Note 13):		
San Onofre Nuclear Generating Station additional requirement for plant closure	-	(5,748)
Change in net position	(2,211)	8,190
NET POSITION, BEGINNING OF YEAR	505,563	497,373
NET POSITION, END OF YEAR	$ 503,352	$ 505,563

See accompanying notes to financial statements

ELECTRIC UTILITY:
FINANCIAL STATEMENTS

STATEMENTS OF CASH FLOWS

	For the Fiscal Years Ended June 30, 2023	2022
	(in thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Cash received from customers and users	$ 430,913	$ 394,707
Cash paid to suppliers for goods and services	(290,354)	(252,247)
Cash paid to employees for services	(56,730)	(47,823)
Net cash provided/(used) by operating activities	**83,829**	**94,637**
CASH FLOWS FROM NON-CAPITAL FINANCING ACTIVITIES:		
Cash transfers out	(42,326)	(39,436)
Payment receipt from advances to other funds	451	471
Debt service payment on pension obligation bonds	(4,232)	(3,310)
Other non-operating receipts	5,140	6,463
Net cash provided/(used) by non-capital financing activities	**(40,967)**	**(35,812)**
CASH FLOWS FROM CAPITAL AND RELATED FINANCING ACTIVITIES:		
Acquisition and construction of capital assets	(27,183)	(32,361)
Principal paid on capital debt	(17,124)	(16,581)
Interest paid on capital debt	(26,149)	(25,645)
Contributions	4,951	5,445
Proceeds from sales of capital assets	5,673	535
Lease and subscription payments	(215)	(126)
Net cash provided/(used) by capital and related financing activities	**(60,047)**	**(68,733)**
CASH FLOWS FROM INVESTING ACTIVITIES:		
Income (loss) from investments	5,582	(10,407)
Proceeds from/(purchase of) investment securities	(4,350)	6,164
Net cash provided/(used) by investing activities	**1,232**	**(4,243)**
Net increase/(decrease) in cash and cash equivalents	**(15,953)**	**(14,151)**
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR (including $63,558 and $64,587 at June 30, 2022 and June 30, 2021, respectively, reported in restricted accounts)	337,730	351,881
CASH AND CASH EQUIVALENTS, END OF YEAR (including $73,946 and $63,558 at June 30, 2023 and June 30, 2022, respectively, reported in restricted accounts)	$ 321,777	$ 337,730

See accompanying notes to financial statements

ELECTRIC UTILITY:
FINANCIAL STATEMENTS

STATEMENT OF CASH FLOWS

	For the Fiscal Years Ended June 30, 2023	2022
	(in thousands)	
RECONCILIATION OF OPERATING INCOME TO NET CASH PROVIDED BY OPERATING ACTIVITIES:		
Operating income (loss)	41,740	73,980
Adjustments to reconcile operating income/(loss) to net cash provided/(used) by operating activities:		
Depreciation	38,189	36,718
Amortization	214	134
(Increase) decrease in utility billed receivable	9,137	(3,908)
(Increase) decrease in utility unbilled receivable	2,985	(931)
(Increase) decrease in accounts receivable	732	(1,487)
(Increase) decrease in prepaid items	679	1,482
(Increase) decrease in deposits	(79)	-
(Increase) decrease in inventory	(979)	485
(Increase) decrease in intergovernmental receivable	(20)	18
Increase (decrease) in accounts payable	(3,494)	4,044
Increase (decrease) in accrued payroll	192	407
Increase (decrease) in retainage payable	164	134
Increase (decrease) in decommissioning liability	(4,438)	(3,334)
Increase (decrease) in Public Benefit Programs payable	242	385
Increase (decrease) in deposits payable	(154)	1,325
Increase (decrease) in unearned revenue	(1,097)	1,345
Increase (decrease) in compensated absences	278	18
Increase (decrease) in net pension liability	(1,308)	(16,425)
Increase (decrease) in OPEB liability	431	530
Increase (decrease) in Public Benefit Program receivable	415	(283)
Total adjustments	**42,089**	**20,657**
Net cash provided/(used) by operating activities	**$ 83,829**	**$ 94,637**
SCHEDULE OF NON-CASH INVESTING, CAPITAL AND FINANCING ACTIVITIES:		
Capital contributions - capital assets	$ 4,903	$ 2,222
Increase (decrease) in fair value of investments	(529)	(2,656)

See accompanying notes to financial statements

ELECTRIC UTILITY:
NOTES TO THE FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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

BASIS OF ACCOUNTING

The Electric Utility uses the accrual basis of accounting as required for enterprise funds with accounting principles generally accepted in the United States of America as applicable to governments. The accounting records of the 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 distinguishes operating revenues and expenses from non-operating items. Operating revenues and expenses generally result from providing services and producing and delivering goods in connection with an enterprise fund's principal ongoing operations. The principal operating revenues of the Electric Utility are charges to customers for electric sales and services. Operating expenses for the Electric Utility include the cost of electric sales and services, administrative expenses, and depreciation on capital assets. All revenues and expenses not meeting this definition are reported as non-operating revenues and expenses.

IMPLEMENTATION OF NEW ACCOUNTING PRONOUNCEMENTS

In November 2016, the GASB issued Statement No. 83, *Certain Asset Retirement Obligations* (GASB 83). This Statement addresses accounting and financial reporting for certain asset retirement obligations (AROs). An ARO is a legally enforceable liability associated with the retirement of a tangible capital asset. This Statement establishes criteria for (1) determining the timing and pattern of liability recognition and a corresponding deferred outflow, (2) requires liability recognition when it is incurred and reasonably estimable, and (3) requires ARO measurement to be based on the best estimate of the current value of outlays expected to be incurred. If an ARO has been incurred but is not yet recognized because it is not reasonably estimable, the government is required to disclose that fact and the reasons therefor. This Statement will enhance comparability of financial statements among governments by establishing uniform criteria for governments to recognize and measure certain AROs, including obligations that may not have been previously reported. This Statement is effective for reporting periods beginning after June 15, 2020.

According to *Clearwater Power Plant Asset Purchase and Sale Agreement* dated March 3, 2010, the City of Riverside purchased the Clearwater Power Plant (the "Plant") from the City of Corona to own, operate, and pay all costs related to the Plant and the assets, as set forth in the agreement. On August 26, 2010, Temporary Right of Entry Agreement was made and entered into between the City of Riverside ("Riverside") and the City of Corona ("Corona") in which Corona leased the Corona Clearwater Cogeneration Facility (the "Property") to Riverside for its operation and maintenance of the Property. Riverside is responsible for plant decommissioning and site restoration related to the Plant. The ARO evaluation study to measure the obligation was completed in fiscal year 2019/20. However, since Riverside does not have the final lease agreement with Army Corps to determine the life of the plant, a liability and deferred outflow will not be recorded in fiscal year 2022/23.

The following new Governmental Accounting Standards Board (GASB) pronouncements were effective and have been implemented for fiscal year 2022-2023 audit:

GASB Statement No. 91, *Conduit Debt Obligations* - This Statement clarifies the existing definition of a conduit debt obligation; establishes that a conduit debt obligation is not a liability of the issuer; establishes standards for accounting and financial reporting of additional commitments and voluntary commitments extended by issuers and arrangements associated with conduit debt obligations; and improves required note disclosures.

GASB Statement No. 94, Public-Private and Public-Public Partnerships and Availability Payment Arrangement - A Public-Private and Public-Public Partnerships (PPP) is an arrangement in which a government (the transferor) contracts with an operator (a governmental or nongovernmental entity) to provide public services by conveying control of the right to operate or use a nonfinancial asset, such as infrastructure or other capital asset (the underlying PPP asset), for a period of time in an exchange or exchange-like transaction. Some PPPs meet the definition of a service concession arrangement (SCA) in

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

IMPLEMENTATION OF NEW ACCOUNTING PRONOUNCEMENTS (CONTINUED)

which (1) the operator collects and is compensated by fees from third parties; (2) the transferor determines or has the ability to modify or approve which services the operator is required to provide, to whom the operator is required to provide the services, and the prices or rates that can be charged for the services; and (3) the transferor is entitled to significant residual interest in the service utility of the underlying PPP asset at the end of the arrangement. This Statement also provides guidance for accounting and financial reporting for availability payment arrangements (APAs). An APA is an arrangement in which a government compensates an operator for services that may include designing, constructing, financing, maintaining, or operating an underlying nonfinancial asset for a period of time in an exchange or exchange-like transaction.

GASB Statement No. 96, *Subscription-Based Information Technology Arrangements* (SBITA) – This Statement defines Subscription-Based Information Technology Arrangements (SBITA) as a contract that conveys control of the right to use another party's (a SBITA vendor's) information technology (IT) software, alone or in combination with tangible capital assets (the underlying IT assets), as specified in the contract for a period of time in an exchange or exchange-like transaction. This Statement establishes that a SBITA results in a subscription asset—an intangible asset—and a corresponding subscription liability; (3) provides the capitalization criteria for outlays other than subscription payments, including implementation costs of a SBITA; and (4) requires note disclosures regarding a SBITA. The standards for SBITAs are based on the standards established in Statement No. 87, *Leases*, as amended.

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, liabilities, revenues and expenses during a reporting period. Accordingly, actual results could differ from those estimates.

REVENUE RECOGNITION

The Electric Utility customers are billed monthly. Unbilled electric service charges, including Public Benefit Programs, are recorded at year-end and are included in accounts receivable. Unbilled accounts receivable totaled $14,004 at June 30, 2023, and $17,075 at June 30, 2022.

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

ELECTRIC UTILITY PLANT AND DEPRECIATION

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

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

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

RESTRICTED ASSETS

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

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 Statements of Net Position, Statements of Revenues, Expenses and Changes in Net Position, and Statements of Cash Flows.

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 held at fiscal agent. 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.

CASH AND INVESTMENTS

The Electric Utility's cash and investments, except for funds required to be held by outside fiscal agents under the provisions of bond indentures, which are administered by outside agencies, are invested in the cash and investment pool of the City.

The Electric Utility values its cash and investments in accordance with provisions of GASB Statement No. 72, *Fair Value Measurement and Application*, which requires governmental entities to use valuation techniques that are appropriate under the circumstances and for which sufficient data are available to measure fair value. The techniques should be consistent with one or more of the following approaches: the market approach, the cost approach or the income approach. Valuation includes a hierarchy of inputs with three distinct levels. Level 1 are quoted prices in an active market for identical assets; Level 2 inputs are significant other observable inputs; and Level 3 inputs are significant unobservable inputs. The Electric Utility does not value any of its investments using level 3 inputs.

City-wide information concerning cash and investments as of June 30, 2023, including authorized investments, fair value measurement and application, custodial credit risk, credit and interest rate risk for debt securities and concentration of investments, carrying amount and market value of deposits and investments can be found in the notes to the City's financial statements in the City's Annual Comprehensive Financial Report.

CASH AND INVESTMENTS AT FISCAL AGENTS

Cash and investments maintained by fiscal agents are considered restricted by the Electric Utility. A portion is pledged as collateral for payment of principal and interest on outstanding bonds and certain funds are set aside to decommission the Electric Utility's proportionate share of Units 2 and 3 at SONGS. Further details regarding the jointly-owned project SONGS can be found in Note 10.

DESIGNATED CASH RESERVES

The Riverside Public Utilities Cash Reserve Policy establishes several designated cash reserves in the Electric Utility for strategic purposes. Designated reserves are set aside for specific purposes determined by the Board of Public Utilities and City Council. Designated reserves may be held for capital or operating purposes.

Designated cash reserve balances as of June 30, 2023 and 2022 were as follows: Additional Decommissioning Liability Reserve $8,644 and $16,107, Customer Deposits $4,948 and $5,610, Capital Repair and Replacement Reserve $2,287

ELECTRIC UTILITY:
NOTES TO THE FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

DESIGNATED CASH RESERVES (CONTINUED)

and $2,488, Electric Reliability Reserve $87,127 and $82,261, Mission Square Improvement Reserve $2,113 and $1,533, and Dark Fiber Reserve $4,801 and $4,942. The combined total for these reserves was $109,920 and $112,941 at June 30, 2023 and 2022, respectively, and is included as a component of unrestricted cash and cash equivalents in the accompanying Statements of Net Position.

ADVANCES TO OTHER FUNDS OF THE CITY

Advances to other funds of the City have been recorded as a result of agreements between the Electric Utility and the City. The balances as of June 30, 2023 and 2022 are $2,003 and $2,454, respectively.

DERIVATIVES

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

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

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

BOND PREMIUMS AND GAINS/LOSSES ON REFUNDING

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

CUSTOMER DEPOSITS

The City holds customer deposits as security for the payment of utility bills and design fee deposits for future construction of electrical facilities. The Electric Utility's portion of these deposits as of June 30, 2023 and 2022 was $11,734 and $11,888, respectively.

COMPENSATED ABSENCES

The accompanying financial statements include accruals for salaries, fringe benefits and compensated absences due to employees at June 30, 2023 and 2022. The Electric Utility treats compensated absences due to employees as an expense and a liability of which a current portion is included in accounts payable and other accruals in the accompanying Statements of Net Position. The amount accrued for compensated absences was $7,478 at June 30, 2023 and $7,200 at June 30, 2022.

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.

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, for a shared limit of $1 billion and $210 million to cover power generation facilities.

City-wide information concerning risks, insurance policy limits and deductibles and designation of general fund balance for risk for the year ended June 30, 2023 may be found in the notes to the City's financial statements in the City's Annual Comprehensive Financial Report.

Although the ultimate amount of losses incurred through June 30, 2023 is dependent upon future developments, management believes that amounts paid to the City are sufficient to cover such losses. Premiums paid to the City by the Electric Utility, including the Public Benefit Programs, were $2,058 and $656 for the years ended June 30, 2023 and 2022, 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 (CalPERS), an agent multiple employer public employee defined benefit pension plan. CalPERS provides retirement and disability benefits, annual cost-of-living adjustments, and death benefits to plan members and beneficiaries. CalPERS acts as a common investment and administrative agent for participating public entities within the State of California. Benefit provisions and all other requirements are established by state statute and City ordinance.

For purposes of measuring the net pension asset/liability and deferred outflows/inflows of resources related to pensions and pension expense, information about the fiduciary net position of the City of Riverside California Public Employees' Retirement System plans (Plans) and additions to/deductions from the Plans' fiduciary net position have been determined on the same basis as they are reported by CalPERS. For this purpose, benefit payments (including refunds of employee contributions) are recognized when due and payable in accordance with the benefit terms. Investments are reported at fair value. Further details of employee retirement plan can be found in Note 6.

OTHER POSTEMPLOYMENT BENEFITS (OPEB)

OPEB refers to the benefits, other than pensions, that the City provides as part of an employee's retirement benefits. The net OPEB liability is defined as the liability of employers contributing to employees for benefits provided through a defined benefit OPEB plan that is administered through a trust. Further details for OPEB can be found in Note 7.

DEFERRED OUTFLOWS AND DEFERRED INFLOWS OF RESOURCES

When applicable, the Statements of Net Position will report a separate section for deferred outflows of resources. Deferred outflows of resources represent outflows of resources (consumption of net position) that apply to future periods and that, therefore, will not be recognized as an expense or expenditure until that time. Deferred outflows of resources consist of changes in derivative values, loss on refunding and deferred outflows related to pension and OPEB, which include pension contributions subsequent to measurement date, difference between actual and actuarial determined contribution, changes in assumptions and net differences between projected and actual earnings on pension plan investments.

Conversely, deferred inflows of resources represent inflows of resources (acquisition of net position) that apply to future periods and that, therefore, are not recognized as an inflow of resources (revenue) until that time. Deferred inflows of resources consist of lease related items, deferred inflows related to pension and OPEB, which include changes in assumptions, differences between expected and actual experience, and net differences between projected and actual earnings on pension plan investments.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

REGULATORY ASSETS

In accordance with regulatory accounting criteria set forth in GASB Codification (GASB Statement No. 62), enterprise funds that are used to account for rate-regulated activities are permitted to defer certain expenses and revenues that would otherwise be recognized when incurred, provided that the Electric Utility is recovering or expects to recover or refund such amounts in rates charged to its customers. Accordingly, regulatory assets relating to debt issuance costs have been recognized in the Statements of Net Position.

NET POSITION

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

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

Restricted – this component represents restricted assets less liabilities and deferred inflows related to those assets. Restricted assets are recorded when there are limitations imposed by creditors (such as through debt covenants), contributors, or laws or regulation of other governments or constraints imposed by law through constitutional provisions or through enabling legislation.

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

CONTRIBUTIONS TO THE CITY'S GENERAL FUND

Pursuant to the City of Riverside Charter, the Electric Utility may transfer up to 11.5 percent of its prior year's gross operating revenues, including adjustments, to the City's general fund. In fiscal years ended June 30, 2023 and 2022, $42,326 and $39,436, respectively, was transferred, representing 11.5 percent. Additional information can be found in Note 12 of the accompanying financial statements.

LEASES AND SUBSCRIPTION-BASED INFORMATION TECHNOLOGY ARRANGEMENTS

Leases are defined by the general government as the right to use an underlying asset. As lessee, the Electric Utility recognizes a lease liability and a lease asset at the beginning of a lease period unless the lease is considered a short-term lease or transfers ownership of the underlying asset. Lease assets are measured based on the net present value of the future lease payments at inception, using the weighted average cost of capital, which approximate the incremental borrowing rate. Re-measurement of a lease liability occurs when there is a change in the lease term and/or other changes that are likely to have a significant impact on the lease liability. The Electric Utility calculates the amortization of the discount on the lease liability and report that amount as outflows of resources. Payments are allocated first to accrued interest liability and then to the lease liability. Variable lease payments based on the usage of the underlying assets are not included in the lease liability calculations but are recognized as outflows of resources in the period in which the obligation was incurred. As lessor, the Electric Utility recognizes a lease receivable. The lease receivable is measured using the net present value of future lease payments to be received for the lease term and deferred inflow of receivables at the beginning of the lease term. Periodic amortization of the discount on the receivable are reported as interest revenue for that period. Deferred inflows of resources are recognized as inflows on a straight-line basis over the term of the lease. This recognition does not apply to short-term leases, contracts that transfer ownership, leases of assets that are investments, or certain regulated leases. Any initial direct costs are reported as an outflow of resources for that period. Re-measurement of lease receivables occur when there are modifications, including but not limited to changes in the contract price, lease term, and adding or removing an underlying asset to the lease agreements. In the case of a partial or full lease termination, the carrying value of the lease receivable and the related deferred inflow of resources will be reduced and will include a gain or loss for the difference. For lease contracts that are short-term, the Electric Utility recognizes short-term lease payments as inflows of resources (revenues) based on the payment provisions of the lease contract. Liabilities are only recognized if payments are received in advance, and receivables are only recognized if payments are received subsequent to the reporting period. Additional disclosures regarding regulated leases are in Note 14.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

LEASES AND SUBSCRIPTION-BASED INFORMATION TECHNOLOGY ARRANGEMENTS (CONTINUED)

Subscription-Based Information Technology Arrangements (SBITAs) are contracts that convey control of the right to use another party's IT software, alone or in combination with tangible capital assets, as specified in the contract for a period of time in an exchange or exchange-like transaction. To determine whether a contract conveys control of the right to use the underlying IT assets, the City assesses both the right to obtain the present service capacity from use of the underlying IT assets and the right to determine the nature and manner of use of the underlying IT assets as specified in the contract. Contracts that solely provide IT support services are excluded from the definition of a SBITA. The subscription term is the period during which the City has a noncancellable right to use the underlying IT assets, plus the periods covered by the City's option to extend the SBITA if it is reasonably certain, based on all relevant factors, that the government will exercise that option. Periods for which both the government and the SBITA vendor have an option to terminate the SBITA without permission from the other party (or if both parties have to agree to extend) are cancellable periods and are excluded from the subscription term. Additional disclosures regarding SBITAs are in Note 14.

BUDGET AND BUDGETARY ACCOUNTING

The Electric Utility presents, and the City Council adopts, a biennial budget. The proposed budget includes estimated expenses and forecasted revenues. The City Council generally adopts the Electric Utility's budget in June biennially via resolution. Per City Council direction, the Electric Utility transitioned from an incremental budget methodology to a priority-based budgeting methodology in fiscal year 2022-2023.

RECLASSIFICATIONS

Certain reclassifications have been made to prior year's financial statements to conform with the current year's presentation. Such reclassifications have no effect on the net position or the changes in net position.

2. CASH AND INVESTMENTS

Cash and investments at June 30, 2023 and 2022, consist of the following (in thousands):

	June 30, 2023	June 30, 2022
	Fair Value	
Equity interest in City Treasurer's investment pool	$ 321,777	$ 337,730
Cash and investments at fiscal agent	58,135	53,785
Total cash and investments	$ 379,912	$ 391,515

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

	June 30, 2023	June 30, 2022
Unrestricted cash and cash equivalents	$ 247,831	$ 274,172
Restricted cash and cash equivalents	73,946	63,558
Restricted cash and investments at fiscal agent	58,135	53,785
Total cash and investments	$ 379,912	$ 391,515

The investment types in the tables below related to the Electric Utility's investments in the City Treasurer's investment pool represent the Electric Utility's prorated share of the investment types in the investment pool and do not represent ownership interests in the individual investments.

ELECTRIC UTILITY:
NOTES TO THE FINANCIAL STATEMENTS

2. CASH AND INVESTMENTS (CONTINUED)

The Electric Utility categorizes its fair value measurements within the fair value hierarchy established by generally accepted accounting principles. The Electric Utility has the following recurring fair value measurements as of June 30, 2023 and 2022:

Investment Type	June 30, 2023 Fair Value	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Investments not Subject to Fair Value Hierarchy
Held by fiscal agent					
Money market funds	$ 1,263	$ -	$ -	$ -	$ 1,263
Asset-backed securities	3,853	-	3,853	-	-
Investment contracts	10,761	-	-	-	10,761
US Treasury notes/bonds	24,065	-	24,065	-	-
Federal agency obligations	3,407	-	3,407	-	-
Corp medium term notes	11,264	-	11,264	-	-
Supranational securities	3,522	-	3,522	-	-
City Treasurer's investment pool[1]					
Money market funds	5,825	-	-	-	5,825
Joint powers authority pools	62,073	-	-	-	62,073
Mortgage pass-through securities	10,596	-	10,596	-	-
Asset-backed securities	26,896	-	26,896	-	-
US Treasury obligations	93,152	-	93,152	-	-
Federal agency obligations	44,548	-	44,548	-	-
Medium-term corporate notes	67,044	-	67,044	-	-
Supranational securities	11,643	-	11,643	-	-
Total	$ 379,912	$ -	$ 299,990	$ -	$ 79,922

Investment Type	June 30, 2022 Fair Value	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Investments not Subject to Fair Value Hierarchy
Held by fiscal agent					
Money market funds	$ 3,728	$ -	$ -	$ -	$ 3,728
Asset-backed securities	3,503	-	3,503	-	-
Investment contracts	10,761	-	-	-	10,761
US Treasury notes/bonds	18,274	-	18,274	-	-
Federal agency obligations	3,208	-	3,208	-	-
Corp medium term notes	10,745	-	10,745	-	-
Supranational securities	3,566	-	3,566	-	-
City Treasurer's investment pool[1]					
Money market funds	9,369	-	-	-	9,369
Joint powers authority pools	52,571	-	-	-	52,571
Local agency investment fund	39,946	-	-	-	39,946
Mortgage pass-through securities	13,210	-	13,210	-	-
Asset backed securities	26,715	-	26,715	-	-
US Treasury obligations	76,259	-	76,259	-	-
Federal agency obligations	45,087	-	45,087	-	-
Medium-term corporate notes	59,240	-	59,240	-	-
Supranational securities	13,748	-	13,748	-	-
Neg certificate of deposit	1,585	-	1,585	-	-
Total	$ 391,515	$ -	$ 275,140	$ -	$ 116,375

[1]Additional information on investment types, fair value measurement, interest rate risk and credit risk may be found in the notes to the City's financial statements in the City's Annual Comprehensive Financial Report.

2. CASH AND INVESTMENTS (CONTINUED)

Cash and investments distribution by maturities as of June 30, 2023 and 2022 are as follows:

Investment Type	June 30, 2023 Fair Value	Remaining Maturity (in Months) 12 Months or Less	13 to 36 Months	37 to 60 Months	More than 60 Months
Held by fiscal agent					
Money market funds	$ 1,263	$ 1,263	$ -	$ -	$ -
Asset-backed securities	3,853	-	2,065	1,788	-
Investment contracts	10,761	-	-	-	10,761
US Treasury notes/bonds	24,065	5,356	12,068	6,641	-
Federal agency obligations	3,407	-	3,407	-	-
Corp medium term notes	11,264	1,311	8,899	1,054	-
Supranational securities	3,522	-	3,522	-	-
City Treasurer's investment pool[1]					
Money market funds	5,825	5,825	-	-	-
Joint powers authority pools	62,073	62,073	-	-	-
Mortgage pass-through securities	10,596	1,668	3,847	5,081	-
Asset-backed securities	26,896	298	11,998	14,600	-
US Treasury obligations	93,152	15,330	27,517	50,305	-
Federal agency obligations	44,548	10,572	27,062	6,914	-
Medium-term corporate notes	67,044	3,347	36,482	27,215	-
Supranational securities	11,643	-	11,643	-	-
Total	$ 379,912	$ 107,043	$ 148,510	$ 113,598	$ 10,761

Investment Type	June 30, 2022 Fair Value	Remaining Maturity (in Months) 12 Months or Less	13 to 36 Months	37 to 60 Months	More than 60 Months
Held by fiscal agent					
Money market funds	$ 3,728	$ 3,728	$ -	$ -	$ -
Asset-backed securities	3,503	-	1,401	2,102	-
Investment contracts	10,761	-	-	-	10,761
US Treasury notes/bonds	18,274	5,995	4,938	7,341	-
Federal agency obligations	3,208	2,622	586	-	-
Corp medium term notes	10,745	-	6,665	4,080	-
Supranational securities	3,566	-	1,687	1,879	-
City Treasurer's investment pool[1]					
Money market funds	9,369	9,369	-	-	-
Joint powers authority pools	52,571	52,571	-	-	-
Local agency investment fund	39,946	39,946	-	-	-
Mortgage pass-through securities	13,210	3,683	7,692	1,835	-
Asset backed securities	26,715	-	14,329	12,386	-
US Treasury obligations	76,259	9,172	37,040	30,047	-
Federal agency obligations	45,087	7,029	28,256	9,802	-
Medium-term corporate notes	59,240	2,716	26,624	29,900	-
Supranational securities	13,748	-	4,774	8,974	-
Neg certificate of deposit	1,585	1,585	-	-	-
Total	$ 391,515	$ 138,416	$ 133,992	$ 108,346	$ 10,761

[1] Additional information on investment types, fair value measurement, interest rate risk and credit risk may be found in the notes to the City's financial statements in the City's Annual Comprehensive Financial Report.

2. CASH AND INVESTMENTS (CONTINUED)

Presented below is the actual rating as of June 30, 2023 and 2022 for each investment type:

Investment Type	June 30, 2023 Fair Value	Ratings as of Year End AAA	AA	A	Unrated
Held by fiscal agent					
Money market funds	$ 1,263	$ 999	$ -	$ -	$ 264
Asset-backed securities	3,853	2,815	-	-	1,038
Investment contracts	10,761	-	-	-	10,761
US Treasury notes/bonds	24,065	23,082	-	983	-
Federal agency obligations	3,407	1,376	-	-	2,031
Corp medium term notes	11,264	-	2,754	6,612	1,898
Supranational securities	3,522	1,850	-	-	1,672
City Treasurer's investment pool[1]					
Money market funds	5,825	5,825	-	-	-
Joint powers authority pools	62,073	-	-	-	62,073
Mortgage pass-through securities	10,596	10,596	-	-	-
Asset-backed securities	26,896	20,340	-	-	6,556
US Treasury obligations	93,152	93,152	-	-	-
Federal agency obligations	44,548	37,720	-	-	6,828
Medium-term corporate notes	67,044	2,120	23,200	32,733	8,991
Supranational securities	11,643	5,995	-	-	5,648
Total	$ 379,912	$ 205,870	$ 25,954	$ 40,328	$ 107,760

Investment Type	June 30, 2022 Fair Value	Ratings as of Year End AAA	AA	A	Unrated
Held by fiscal agent					
Money market funds	$ 3,728	$ 2,787	$ -	$ -	$ 941
Asset-backed securities	3,503	2,869	-	-	634
Investment contracts	10,761	-	-	-	10,761
US Treasury notes/bonds	18,274	18,274	-	-	-
Federal agency obligations	3,208	3,208	-	-	-
Corp medium term notes	10,745	-	2,753	6,657	1,335
Supranational securities	3,566	1,879	-	-	1,687
City Treasurer's investment pool[1]					
Money market funds	9,369	7,305	-	-	2,064
Joint powers authority pools	52,571	-	-	-	52,571
Local agency investment fund	39,946	-	-	-	39,946
Morgage pass-through securities	13,210	13,210	-	-	-
Asset backed securities	26,715	21,272	-	-	5,443
US Treasury obligations	76,259	76,259	-	-	-
Federal agency obligations	45,087	45,087	-	-	-
Medium-term corporate notes	59,240	-	21,023	32,327	5,890
Supranational securities	13,748	7,106	-	-	6,642
Neg certificate of deposit	1,585	-	-	1,585	-
Total	$ 391,515	$ 199,256	$ 23,776	$ 40,569	$ 127,914

[1] Additional information on investment types, fair value measurement, interest rate risk and credit risk may be found in the notes to the City's financial statements in the City's Annual Comprehensive Financial Report.

ELECTRIC UTILITY:
NOTES TO THE FINANCIAL STATEMENTS

3. CAPITAL ASSETS

The following is a summary of changes in utility plant and lease and subscription assets during the fiscal years ended June 30, 2023 and 2022:

	Balance As of 6/30/2021	Additions	Retirements/ Transfers	Balance As of 6/30/2022	Additions	Retirements/ Transfers	Balance As of 6/30/2023
Production	$ 269,248	$ 566	$ -	$ 269,814	$ 119	$ (3,967)	$ 265,966
Transmission	49,079	1,338	-	50,417	2,999	-	53,416
Distribution	706,807	22,300	(3,948)	725,159	21,894	(5,176)	741,877
General	117,696	6,159	(423)	123,432	3,487	(4,792)	122,127
Intangibles	21,986	3,977	-	25,963	704	-	26,667
Depreciable utility plant	1,164,816	34,340	(4,371)	1,194,785	29,203	(13,935)	1,210,053
Less accumulated depreciation:							
Production	(111,878)	(9,040)	-	(120,918)	(9,032)	397	(129,553)
Transmission	(21,401)	(972)	-	(22,373)	(1,004)	-	(23,377)
Distribution	(302,455)	(19,440)	3,917	(317,978)	(20,043)	4,247	(333,774)
General	(54,007)	(4,816)	423	(58,400)	(5,272)	4,575	(59,097)
Intangibles	(13,347)	(2,450)	-	(15,797)	(2,838)	-	(18,635)
Accumulated depreciation	(503,088)	(36,718)	4,340	(535,466)	(38,189)	9,219	(564,436)
Net depreciable utility plant	661,728	(2,378)	(31)	659,319	(8,986)	(4,716)	645,617
Land	53,042	-	-	53,042	3,344	-	56,386
Intangible, non-amortizable	10,651	-	-	10,651	-	-	10,651
Construction in progress	72,481	32,361	(32,118)	72,724	27,125	(27,587)	72,262
Nondepreciable utility plant	136,174	32,361	(32,118)	136,417	30,469	(27,587)	139,299
Total utility plant	$ 797,902	$ 29,983	$ (32,149)	$ 795,736	$ 21,483	$ (32,303)	$ 784,916
Lease and subscription assets, being amortized:[1]							
Building - intangible	$ -	$ 348	$ -	$ 348	$ -	$ -	$ 348
Machinery and equipment - intangible	-	280	-	280	-	-	280
Subscription-based information technology arrangements	-	-	-	-	128	(35)	93
Total lease and subscription assets	-	628	-	628	-	-	721
Less lease accumulated amortization:							
Machinery and equipment - intangible	-	(62)	-	62	(62)	-	(124)
Building - intangible	-	(75)	-	75	(74)	-	(149)
Subscription-based information technology arrangements	-	-	-	-	(78)	35	(43)
Total lease accumulated amortization	-	(137)	-	(137)	(214)	-	(316)
Total lease and subscription assets, net	$ -	$ 491	$ -	$ 491	$ (86)	$ -	$ 405
Total capital assets being depreciated, net	**$ 797,902**	**$ 30,474**	**$ (32,149)**	**$ 796,227**	**$ 21,397**	**$ (32,303)**	**$ 785,321**

[1] GASB 87 *Leases* was implemented effective July 1, 2021. GASB 96 *Subscription-Based Information Technology Arrangements* (SBITA) was implemented effective July 1, 2022. For additional information, refer to Notes 1 and 14.

4. LONG-TERM OBLIGATIONS

The following is a summary of changes in long-term obligations during the fiscal years ended June 30, 2023 and 2022 (in thousands):

	Balance As of 6/30/2021	Additions	Reductions	Balance As of 6/30/2022	Additions	Reductions	Balance As of 6/30/2023	Due Within One Year
Revenue bonds	$ 587,822	$ -	$ (18,637)	$ 569,185	$ -	$ (19,358)	$ 549,827	$ 17,515
Pension obligation bonds	70,951	-	(3,310)	67,641	-	(4,233)	63,408	5,118
Direct borrowings:								
Financed purchases	909	-	(545)	364	-	(364)	-	-
Total long-term obligations	$ 659,682	$ -	$ (22,492)	$ 637,190	$ -	$ (23,955)	$ 613,235	$ 22,633

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

Pension Obligation Bonds Payable

	June 30, 2023	June 30, 2022
$31,960 2017 Taxable Pension Obligation Bonds Series A: fixed rate bonds issued by the City due in annual installments from $2,910 to $3,580 through June 2027, with coupons from 1.3 to 3.1 percent. The Electric Utility's proportional share of the outstanding debt is 29.4 percent.	$ 4,065	$ 5,014
$201,080 2020 Taxable Pension Obligation Bonds Series A (Miscellaneous): fixed rate bonds issued by the City due in annual installments from $1,285 to $14,625 through June 2045, with coupons from 1.6 to 3.9 percent. The Electric Utility's proportional share of the outstanding debt is 32.9 percent.	59,343	62,627
Total pension obligation bonds payable	63,408	67,641

4. LONG-TERM OBLIGATIONS (CONTINUED)

Revenue Bonds Payable

	June 30, 2023	June 30, 2022
$141,840 2008 Electric Refunding/Revenue Bonds:		
A - $84,515 2008 Series A Bonds - variable rate bonds due in annual principal installments from $4,575 to $7,835 through October 1, 2029. Interest rate is subject to weekly repricing (net interest rate, including swaps, at June 30, 2023 was 3.0 percent). Partially refunded $13,975 on July 25, 2013 with the 2013 Electric Revenue Refunding Bonds. Partially refunded $31,500 on April 1, 2019 with 2019A Electric Refunding Bonds.	$ 34,465	$ 34,465
C - $57,325 2008 Series C Bonds - variable rate bonds due in annual principal installments from $700 to $5,200 through October 1, 2035. Interest rate is subject to weekly repricing (net interest rate, including swaps, at June 30, 2023 was 3.1 percent). Partially refunded $11,775 on July 25, 2013 with the 2013 Electric Revenue Refunding Bonds. Partially refunded $8,925 on April 1, 2019 with 2019A Electric Refunding Bonds.	32,150	32,150
$133,290 2010 Electric Revenue Series A Bonds: fixed rate, federally taxable Build America Bonds due in annual principal installments from $2,300 to $33,725, through October 1, 2040, interest from 3.9 to 4.9 percent	126,110	128,600
$56,450 2011 Electric Revenue/Refunding Series A Bonds: fixed rate bonds due in annual principal installments from $725 to $5,175 through October 1, 2035, interest of 3.2 percent	33,600	35,550
$79,080 2013 Electric Revenue Refunding Series A Bonds: fixed rate bonds due in annual principal installments from $795 to $2,625 through October 1, 2043, interest from 3.0 to 5.25 percent	35,385	36,355
$283,325 2019 Electric Revenue Refunding Series A Bonds: fixed rate bonds due in annual principal installments from $3,545 to $24,005 through October 1, 2048, interest of 5.0 percent	245,660	257,010
Total electric revenue bonds payable	507,370	524,130
Total electric revenue and pension obligation bonds payable	570,778	591,771
Unamortized bond premium	42,457	45,055
Total electric revenue and pension obligation bonds payable, including bond premium	613,235	636,826
Less current portion of revenue and pension obligation bonds payable	(22,633)	(20,992)
Total long-term electric revenue and pension obligation bonds payable	$ 590,602	$ 615,834

The Electric Utility is obligated to pay its share of the City's pension obligation bonds, which the City issued in 2005 and refinanced a portion in May 2017.

In fiscal year ended June 30, 2020, the City issued $432,165 2020 Taxable Pension Obligation Bonds Series A. The bonds were issued to reduce the City's unfunded pension liability in both the City's Miscellaneous and Safety CalPERS plans. It is estimated the issuance will save the City's General Fund approximately $178.5 million throughout the life of the bonds. The fixed rate bonds issued by the City are due in annual installments from $1,285 to $14,625 through June 2045, with coupons from 1.6 to 3.9 percent. The Electric Utility's proportional share of the miscellaneous plan is 32.9 percent.

The Electric Utility's proportional share of the outstanding principal amount of the bonds was $63,408 and $67,641 as of June 30, 2023 and 2022, respectively. The bond proceeds were deposited with CalPERS to fund the unfunded actuarial accrued liability for non-safety employees. For more discussion relating to the City's pension obligation bond issuance, see the notes to the City's financial statements in the City's Annual Comprehensive Financial Report for the fiscal year ended June 30, 2023.

4. LONG-TERM OBLIGATIONS (CONTINUED)

Remaining pension obligation bond debt service payments will be made from revenues of the Electric Fund. Annual debt service requirements to maturity as of June 30, 2023 are as follows (in thousands):

Fiscal Year	Principal	Interest	Total
2024	$ 5,118	$ 2,044	$ 7,162
2025	5,675	1,930	7,605
2026	5,839	1,797	7,636
2027	5,596	1,646	7,242
2028	3,800	1,493	5,293
2029-2033	13,766	6,109	19,875
2034-2038	15,507	3,320	18,827
2029-2043	8,107	723	8,830
Total	$ 63,408	$ 19,062	$ 82,470

All electric revenue bonds are covenanted per the Amended and Restated Resolution No. 17662 (Electric) Master Resolution that upon the occurrence and continuation of an event of default, the owners of 25% in aggregate amount of Bond Obligation may, by written notice to the City, declare the entire unpaid principal and accreted value of the bonds due and payable should the City fail to pay its debts as they become due or upon the entry of any decree or order of bankruptcy of the City.

Remaining revenue bond debt service payments will be made from revenues of the Electric Fund. Annual debt service requirements to maturity as of June 30, 2023 are as follows (in thousands):

Fiscal Year	Principal	Interest	Total
2024	$ 17,515	$ 23,362	$ 40,877
2025	18,335	22,488	40,823
2026	19,305	21,580	40,885
2027	20,085	20,742	40,827
2028	20,960	19,864	40,824
2029-2033	118,900	84,562	203,462
2034-2038	138,570	55,605	194,175
2039-2043	121,770	19,283	141,053
2044-2048	26,430	4,532	30,962
2049-2053	5,500	138	5,638
Premium	42,457	-	42,457
Total	$ 549,827	$ 272,156	$ 821,983

The Electric Utility has a number of debt issuances (revenue bonds) outstanding that are collateralized by the pledging of electric revenues. The amount and term of the remainder of these commitments are indicated in the revenue bonds payable and annual debt service requirements to maturity tables presented within this Note 4. The purpose of the debt issuances was for the financing of various Electric Utility capital improvement projects. For June 30, 2023 and 2022, debt service payments as a percentage of the pledged gross revenue, net of certain expenses where so required by the debt agreement, are indicated in the table below. The debt service coverage ratios also approximate the relationship of the debt service to pledged revenue for the remainder of the term of the commitment.

Fiscal Year Ended	Description of Pledged Revenues	Annual Amount of Pledged Revenue (net of expenses) [1,2,3]	Annual Debt Service Payments	Debt Service Coverage Ratio
June 30, 2023	Electric revenues	$ 93,040	$ 46,400	2.01
June 30, 2022	Electric revenues	$ 93,639	$ 46,028	2.03

[1]Excludes GASB 68 *Accounting and Financial Reporting for Pension* non-cash adjustments of $(1,308) and $(16,425) for June 30, 2023 and 2022, respectively.

[2]Excludes GASB 75 Accounting and Financial Reporting for Postemployment Benefits Other Than Pensions non-cash adjustments of $431 and $530 for June 30, 2023 and 2022, respectively.

[3]Includes GASB 87 Leases net revenue adjustment of $247 and $134 for June 30, 2023 and 2022, respectively.

4. LONG-TERM OBLIGATIONS (CONTINUED)

LINE OF CREDIT

On February 1, 2019, the City entered into a subordinate line of credit agreement with U.S. Bank, National Association. The agreement was renewed on February 1, 2022. The Subordinate Line of Credit is a tool approved through the Electric and Water Utility Five-Year Rate Plan to manage rate increases by enabling the Electric Utility to reduce cash levels while maintaining compliance with the Riverside Public Utilities Cash Reserve Policy. Under the terms and conditions of the agreement, the City may borrow up to $35,000 for purposes of the capital or operating financial needs of the Electric System. There were no borrowings against the line as of June 30, 2023.

LETTERS OF CREDIT

The Electric Utility's 2008 Electric Revenue Bonds (Series A and C) and 2011 Electric Revenue Bonds (Series A) require an additional layer of security between the Electric Utility and the purchaser of the bonds. The Electric Utility has entered into the following letters of credit (LOC) in order to provide liquidity should all or a portion of the debt be optionally tendered to the remarketer without being successfully remarketed:

Debt Issue	LOC Provider	LOC Expiration Date
2008 Electric Refunding/Revenue Bonds Series A	Barclays Bank, PLC	2024
2008 Electric Refunding/Revenue Bonds Series C	Barclays Bank, PLC	2024
2011 Electric Refunding/Revenue Bonds Series A	Bank of America, N.A.	2026

Debt Issue	Annual Commitment Fee
2008 Electric Refunding/Revenue Bonds Series A	0.395 %
2008 Electric Refunding/Revenue Bonds Series C	0.395 %
2011 Electric Refunding/Revenue Bonds Series A	0.350 %

To the extent that remarketing proceeds are insufficient or not available, tendered amounts will be paid from drawings made under an irrevocable direct-pay letter of credit.

Liquidity advances drawn against the LOCs that are not repaid will be converted to an installment loan with principal to be paid quarterly not to exceed a 5-year period for the 2008A and 2008C bonds not to exceed a 3-year period for the 2011A bonds. For the 2008A and 2008C Bonds, the Electric Utility would be required to pay annual interest equal to the Base Rate plus 2 percent, where the Base Rate is the highest of 8 percent, the Prime Rate plus 2.5 percent, the Federal Funds Rate plus 2.5 percent and 150 percent of the yield on the 30-year U.S. Treasury Bond. For the 2011A Bonds, the Electric Utility would be required to pay annual interest equal to the Base Rate plus 2 percent, where the Base Rate is the highest of 10.5 percent, the Prime Rate plus 1 percent and the Federal Funds Rate plus 2 percent. No amounts have ever been drawn against the three LOCs due to a failed remarketing.

The various indentures allow the Electric Utility to convert the mode of the debt in the case of a failed remarketing.

INTEREST RATE SWAPS ON REVENUE BONDS

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

4. LONG-TERM OBLIGATIONS (CONTINUED)

INTEREST RATE SWAPS ON REVENUE BONDS (CONTINUED)

A summary of the derivative activity for the year ended June 30, 2023 is as follows:

	Outstanding Notional Amount	Fair Value as of June 30, 2023	Change in Fair Value for Fiscal Year
2008 Electric Refunding/Revenue Bonds Series A	$ 34,465	$ (491)	$ 1,394
2008 Electric Refunding/Revenue Bonds Series C	$ 32,150	$ (1,809)	$ 1,686
2011 Electric Refunding/Revenue Bonds Series A	$ 33,600	$ (1,797)	$ 1,728

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

Terms: Per the existing swap agreements, the Electric Utility pays the counterparty a fixed payment and receives a variable payment computed as 62.68 percent of the London Interbank Offering Rate ("LIBOR") one month index plus 12 basis points. The swaps have notional amounts equal to the principal amounts stated above. The notional value of the swaps and the principal amounts of the associated debt decline by $6,000 to $7,835 (2008 Series A), $700 to $5,200 (2008 Series C) and $725 to $5,175 (2011 Series A) until the debt is completely retired in fiscal years 2030 (2008 Series A) and 2036 (2008 Series C and 2011 Series A).

The bonds and the related swap agreements for the Electric Refunding/Revenue 2008 (Series A) Bonds mature on October 1, 2029 and the 2008 (Series C) and 2011 (Series A) Bonds mature on October 1, 2035. As of June 30, 2023 rates were as follows:

		2008 Electric Refunding/Revenue Series A Bonds	2008 Electric Refunding/Revenue Series C Bonds	2011 Electric Refunding/Revenue Series A Bonds
Interest rate swap:	Terms	Rates	Rates	Rates
Fixed payment to counterparty	Fixed	3.11100 %	3.20400 %	3.20100 %
Variable payment from counterparty	62.68 LIBOR +	(0.69885)%	(0.69911)%	(0.75953)%
Net interest rate swap payments	12bps	2.41215 %	2.50489 %	2.44147 %
Variable-rate bond coupon payments		0.56351 %	0.57077 %	0.68005 %
Synthetic interest rate on bonds		2.97566 %	3.07660 %	3.12152 %

Fair value: As of June 30, 2023, in connection with all swap agreements, the transactions had a total negative fair value of $(4,097). Because the coupons on the Electric Utility's variable-rate bonds adjust to changing interest rates, the bonds do not have a corresponding fair value decrease. The fair value was developed by a pricing service using the zero-coupon method. This method calculates the future net settlement payments required by the swaps, assuming that the current forward rates implied by the yield curve correctly anticipate future spot interest rates. These payments are then discounted using the spot rates implied by the current yield curve for hypothetical zero-coupon bonds due on the date of each future net settlement of the swap.

Credit risk: As of June 30, 2023, the Electric Utility was not exposed to credit risk because the swaps had a negative fair value. The swaps counterparties, J.P. Morgan Chase & Co. and Bank of America Corp., were rated A- and BBB+ respectively by Standard & Poor's (S&P). To mitigate the potential for credit risk, the swap agreements require the fair value of the swaps to be collateralized by the counterparty with U.S. Government securities if the counterparties' rating decreases to negotiated trigger points. Collateral would be posted with a third-party custodian. At June 30, 2023, there is no requirement for collateral posting for any of the outstanding swaps.

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

Termination risk: The derivative contract uses the International Swap Dealers Association Master Agreement, which includes standard termination events, such as failure to pay and bankruptcy. The Schedule to the Master Agreement includes an "additional termination event." That is, a swap may be terminated by the Electric Utility if either counterparty's

4. LONG-TERM OBLIGATIONS (CONTINUED)

INTEREST RATE SWAPS ON REVENUE BONDS (CONTINUED)

credit quality falls below “BBB-” as issued by S&P. The Electric Utility or the counterparty may terminate a swap if the other party fails to perform under the terms of the contract. If a swap is terminated, the variable-rate bond would no longer carry a synthetic interest rate. Also, if at the time of termination, a swap has a negative fair value, the Electric Utility would be liable to the counterparty for a payment equal to the swap’s fair value.

Swap payments and associated debt: As of June 30, 2023, 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 in the table below. 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
2024	$ 725	$ 671	$ 2,703	$ 4,099
2025	725	665	2,681	4,071
2026	1,450	629	2,532	4,611
2027	7,425	582	2,331	10,338
2028	7,885	531	2,121	10,537
2029-2033	51,980	1,795	7,059	60,834
2034-2038	30,025	274	1,075	31,374
Total	$ 100,215	$ 5,147	$ 20,502	$ 125,864

Replacement of London Interbank Offering Rate (LIBOR): As of July 1, 2023, LIBOR is no longer an appropriate benchmark interest rate for a derivative instrument that hedges the interest risk for taxable debt for purposes of GASB Statement 53.

FINANCED PURCHASES

The Electric Utility has entered into sixteen purchase agreements for financing sixteen compressed natural gas heavy duty service trucks. All agreements have seven-year terms of monthly payments with interest rates ranging from 2.0 percent to 2.5 percent. The total gross value of all existing agreements is $5,715 with depreciation over the seven-year terms using the straight-line method. As of June 30, 2022 the total liability was $364. The final payment on this agreement was made in February 2023, which consisted of $364 principal and $2 interest. No further payments are due.

5. COMPENSATED ABSENCES

A liability is recorded for unused vacation and similar compensatory leave balances since the employees’ entitlement to these balances are attributable to services already rendered and it is probable that virtually all of these balances will be liquidated by either paid time-off or payments upon termination or retirement.

Below is a summary of changes in Compensated absences for the Electric Utility during the fiscal year.

	Balance As of 6/30/2021	Additions	Reductions	Balance As of 6/30/2022	Additions	Reductions	Balance As of 6/30/2023	Due Within One Year
Compensated absences	$ 7,182	$ 4,780	$ (4,762)	$ 7,200	$ 5,659	$ (5,381)	$ 7,478	$ 5,589

6. EMPLOYEE RETIREMENT PLAN

PLAN DESCRIPTION

The City contributes to CalPERS, an agent multiple employer public employee defined benefit pension plan. CalPERS provides retirement and disability benefits, annual cost-of-living adjustments, and death benefits to plan members and beneficiaries. CalPERS acts as a common investment and administrative agent for participating public entities within the State of California. CalPERS issues a publicly available financial report that includes financial statements and required supplementary information for the cost sharing plans that are administered by CalPERS. Benefit provisions and all other requirements are established by state statute and City ordinance. A copy of CalPERS' annual financial report may be obtained online at www.calpersca.gov. The Electric Utility participates in the City's Miscellaneous (non-safety) Plan (the Plan).

FUNDING POLICY

The City has contributed at the actuarially determined rate provided by CalPERS' actuaries. Participants are required to contribute 8% of their annual covered salary. The City has a multiple tier retirement plan with benefits varying by plan. All permanent full-time and selected part-time employees are eligible for participation in CalPERS. Benefits vest after five years of service and are determined by a formula that considers the employee's age, years of service and salary. Under the Plan, the City pays the employees' contribution to CalPERS for employees hired on or before specific dates as follows:

- 1st Tier –
  - The retirement formula is 2.7% at age 55 for employees hired on or before October 18, 2011. Effective January 1, 2018 for unrepresented employees (Sr. Management, Management, Professional, Para-professional, Supervisory, Confidential, and Executive units, excluding the Chief of Police and the Fire Chief), the employees were required to pay 2% of their pensionable income, with the City contributing the other 6%. Effective January 1, 2019, employees were required to pay an additional portion of their pensionable income. This portion was a three-year increase of 2% (2019), 2% (2020) and 2% (2021). As of 2021, employees are contributing the entire 8% of their pensionable income.

  - The retirement formula is 2.7% at age 55 for SEIU and SEIU Refuse employees hired before June 7, 2011. Currently, employees are required to pay 7% of their pensionable income with the City contributing the other 1%. Effective January 1, 2019, employees were required to pay an additional portion of their pensionable income. This portion was a two-year increase of 1% (2019) and 1% (2020). As of 2020, employees are contributing the entire 8% of their pensionable income.

  - The retirement formula is 2.7% at age 55 for IBEW and IBEW Supervisory employees hired on or before October 18, 2011. Effective November 1, 2017, employees were required to pay 2% of their total pensionable income with the City paying the remaining 6%. Effective each November 1st, employees were required to pay an additional portion of their pensionable income. This portion was a three-year increase of 2% (2018), 2% (2019) and 2% (2020). As of November 2020, employees are contributing the entire 8% of their pensionable income.

- 2nd Tier –The retirement formula is 2.7% at age 55, and:
  - Miscellaneous employees, IBEW, and IBEW Supervisory hired on or after October 19, 2011 pay their share (8%) of contributions.

  - SEIU and SEIU Refuse employees hired on or after June 7, 2011 pay their share (8%) of contributions.

- 3rd Tier – The retirement formula is 2% at age 62 for new members hired on or after January 1, 2013 and the employee must pay the normal cost to CalPERS, which is currently at 7.75%. Classic members (CalPERS members prior to 12/31/12) hired on or after January 1, 2013 may be placed in a different tier.

The contribution requirements of plan members and the City are established and may be amended by CalPERS.

6. EMPLOYEE RETIREMENT PLAN (CONTINUED)

BENEFITS PROVIDED

CalPERS provides service retirement and disability benefits, annual cost-of-living adjustments and death benefits to plan members who must be public employees and beneficiaries. Benefits are based on years of credited service, equal to one year of full-time employment. Members with five years of total service are eligible to retire at age 50 with statutorily reduced benefits. All members are eligible for non-duty disability benefits after five years of service. The death benefit is one of the following: the Basic Death Benefit, the 1959 Survivor Benefit Level III, or the Optional Settlement 2W Death Benefit. The cost-of-living adjustments for the Plan are applied as specified by the Public Employees' Retirement Law.

EMPLOYEES COVERED

As of measurement date June 30, 2022 and 2021, the following employees, City-wide, were covered by the benefit terms of the Plan:

	Measurement Date	
	June 30, 2022	June 30, 2021
Inactive employees or beneficiaries currently receiving benefits	2,418	2,373
Inactive employees entitled to but not yet receiving benefits	1,475	1,422
Active employees	1,527	1,508

CONTRIBUTIONS

Section 20814(c) of the California Public Employees' Retirement Law requires that the employer contribution rates for all public employers be determined on an annual basis by the actuary and shall be effective on the July 1 following notice of a change in the rate. Funding contributions for the Plan is determined annually on an actuarial basis as of June 30 by CalPERS. The actuarially determined rate is the estimated amount necessary to finance the costs of benefits earned by employees during the year, with an additional amount to finance any unfunded accrued liability. The City is required to contribute the difference between the actuarially determined rate and the contribution rate of employees.

NET PENSION LIABILITY

The City's net pension liability for the Plan is measured as the total pension liability, less the pension plan's fiduciary net position. For fiscal year ended June 30, 2023, the net pension liability of the Plan is measured as of June 30, 2022, using an annual actuarial valuation as of June 30, 2021 rolled forward to June 30, 2022 using standard update procedures. For fiscal year ended June 30, 2022, the net pension liability of the Plan is measured as of June 30, 2021, using an annual actuarial valuation as of June 30, 2020 rolled forward to June 30, 2021 using standard update procedures. A summary of principal assumptions and methods used to determine the net pension liability is shown below:

ACTUARIAL ASSUMPTIONS

The total pension liabilities in the June 30, 2022 and 2021 actuarial valuations were determined using the following actuarial assumptions:

6. EMPLOYEE RETIREMENT PLAN (CONTINUED)

ACTUARIAL ASSUMPTIONS (CONTINUED)

	Miscellaneous - Current Year	Miscellaneous - Prior Year
Valuation Date	June 30, 2021	June 30, 2020
Measurement Date	June 30, 2022	June 30, 2021
Actuarial Cost Method	Entry-Age Normal Cost Method	Entry-Age Normal Cost Method
Actuarial Assumptions		
Discount Rate	6.90%	7.15%
Inflation	2.30%	2.50%
Salary Increase	Varies by entry age and service	Varies by entry age and service
Mortality Rate Table[1]	Derived using CalPERS' membership data for all funds.	
Post Retirement Benefit Increase	The lesser of contract COLA or 2.30% until Purchasing Power Protection Allowance floor on purchasing power applies, 2.30% thereafter	The lesser of contract COLA or 2.50% until Purchasing Power Protection Allowance floor on purchasing power applies, 2.50% thereafter

[1]The mortality table used was developed based on CalPERS-specific data. The probabilities of mortality are based on the 2021 CalPERS Experience Study for the period from 2001 to 2019. Pre-retirement and Post-retirement mortality rates include generational mortality improvement using 80% of Scale MP-2020 published by the Society of Actuaries. For more details on this table, please refer to the CalPERS Experience Study and Review of Actuarial Assumptions report from November 2021 that can be found on the CalPERS website.

LONG-TERM EXPECTED RATE OF RETURN

The long-term expected rate of return on pension plan investments was determined using a building-block method in expected future real rates of return (expected returns, net of pension plan investment expense and inflation) are developed for each major asset class. In determining the long-term expected rate of return, CalPERS took into account both short-term and long-term market return expectations. Using historical returns of all of the funds' asset classes, expected compound (geometric) returns were calculated over the next 20 years using a buildingblock approach. The expected rate of return was then adjusted to account for assumed administrative expenses of 10 Basis points. The expected real rates of return by asset class are as follows:

June 30, 2022 Measurement Date

Asset Class(1)	Assumed Asset Allocation	Real Return(1),(2)
Global Equity - Cap-weighted	30.00%	4.54%
Global Equity - Non-Cap-weighted	12.00%	3.84%
Private Equity	13.00%	7.28%
Treasury	5.00%	0.27%
Mortgage-backed Securities	5.00%	0.50%
Investment Grade Corporates	10.00%	1.56%
High Yield	5.00%	2.27%
Emerging Market Debt	5.00%	2.48%
Private Debt	5.00%	3.57%
Real Assets	15.00%	3.21%
Leverage	(5.00)%	(0.59)%

(1) An expected inflation of 2.30% used for this period.

(2) Figures are based on the 2021 Asset Liability Management study.

6. EMPLOYEE RETIREMENT PLAN (CONTINUED)

LONG-TERM EXPECTED RATE OF RETURN (CONTINUED)

June 30, 2021 Measurement Date

Asset Class[1]	Current Target Allocation	Real Return Years 1 - 10[2]
Global Equity	50.00%	4.80%
Fixed Income	28.00%	1.00%
Inflation Assets	0.00%	0.77%
Private Equity	8.00%	6.30%
Real Assets	13.00%	3.75%
Liquidity	1.00%	0.00%

June 30, 2021 Measurement Date

Asset Class[1]	Real Return Years 11+[3]
Global Equity	5.98%
Fixed Income	2.62%
Inflation Assets	1.81%
Private Equity	7.23%
Real Assets	4.93%
Liquidity	-0.92%

(1) In the System's ACFR, Fixed Income is included in Global Debt Securities; Liquidity is included in Short-term Investments; Inflation Assets are included in both Global Equity Securities and Global Debt Securities.

(2) An expected inflation of 2.00% used for this period.

(3) An expected inflation of 2.92% used for this period.

DISCOUNT RATE

The discount rate used to measure the total pension liability was 6.90% and 7.15% for measurement dates as of June 30, 2022 and 2021, respectively. The projection of cash flows used to determine the discount rate assumed that contributions from plan members will be made at the current member contribution rates and that contributions from employers will be made at statutorily required rates, actuarially determined. Based on those assumptions, the Plan's fiduciary net position was projected to be available to make all projected future benefit payments of current plan members. Therefore, the long-term expected rate of return on plan investments was applied to all periods of projected benefit payments to determine the total pension liability.

CHANGES IN ASSUMPTIONS

Effective with the June 30, 2021 valuation date (2022 measurement date), the accounting discount rate was reduced from 7.15% to 6.90%. In determining the long-term expected rate of return, CalPERS took into account long-term market return expectations as well as the expected pension fund cash flows. Projected returns for all asset classes are estimated, combined with risk estimates, and are used to project compound (geometric) returns over the long term. The discount rate used to discount liabilities was informed by the long-term projected portfolio return. In addition, demographic assumptions and the inflation rate assumption were changed in accordance with the 2021 CalPERS Experience Study and Review of Actuarial Assumptions.

CHANGES IN THE NET PENSION LIABILITY (ASSET)

The changes in the Electric Utility's proportionate share of the net pension liability/(asset) as of June 30, 2023 (measurement date June 30, 2022) and 2022 (measurement date June 30, 2021) for the Plan are as follows:

6. EMPLOYEE RETIREMENT PLAN (CONTINUED)

CHANGES IN THE NET PENSION LIABILITY (ASSET) (CONTINUED)

June 30, 2023		Net Pension Liability/ (Asset)	Proportion of the Plan
Proportion - Reporting date June 30, 2023 (Measurement Date June 30, 2022)	$	38,748	29.42 %
Proportion - Reporting date June 30, 2022 (Measurement Date June 30, 2021)		(26,219)	29.56 %
Changes - Increase / (Decrease)		64,967	(0.14)%
June 30, 2022			
Proportion - Reporting date June 30, 2022 (Measurement Date June 30, 2021)		(26,219)	29.56 %
Proportion - Reporting date June 30, 2021 (Measurement Date June 30, 2020)		39,233	32.68 %
Changes - Increase / (Decrease)		(65,452)	(3.11)%

PENSION EXPENSES AND DEFERRED OUTFLOWS/INFLOWS OF RESOURCES RELATED TO PENSION

For the fiscal years ended June 30, 2023 and 2022, the Electric Utility recognized pension expense of $7,266 and $(8,343), respectively. At June 30, 2023 and 2022, the Electric Utility reported deferred outflows of resources and deferred inflows of resources related to pension from the following sources:

	June 30, 2023		June 30, 2022	
	Deferred Outflows of Resources	Deferred Inflows of Resources	Deferred Outflows of Resources	Deferred Inflows of Resources
Pension contribution subsequent to the measurement date	$ 8,574	$ -	$ 8,080	$ -
Changes in Assumptions	3,982	-	-	-
Difference between expected and actual experience	263	(3,577)	1,088	-
Net difference between projected and actual earnings on pension plan investments	22,112	-	-	(44,089)
Total	$ 34,931	$ (3,577)	$ 9,168	$ (44,089)

Deferred outflows of resources related to contributions subsequent to the measurement date reported in prior year was recognized as a reduction of the net pension liability in the year ended June 30, 2022.

The remaining amounts reported as deferred outflows of resources and deferred (inflows) of resources related to pensions will be recognized as pension expense as follows:

Year Ended June 30	Deferred Outflows/ (Inflows) of Resources
2024	$ 4,049
2025	3,471
2026	1,500
2027	13,760
Total	$ 22,780

6. EMPLOYEE RETIREMENT PLAN (CONTINUED)

PENSION EXPENSES AND DEFERRED OUTFLOWS/INFLOWS OF RESOURCES RELATED TO PENSION (CONTINUED)

Subsequent Events - On July 12, 2021, CalPERS reported a preliminary 21.3% net return on investments for fiscal year 2020-21. Based on the thresholds specified in CalPERS Funding Risk Mitigation policy, the excess return of 14.3% prescribes a reduction in investment volatility that corresponds to a reduction in the discount rate used for funding purposes of 0.20%, from 7.00% to 6.80%. Since CalPERS was in the final stages of the four-year Asset Liability Management (ALM) cycle, the board elected to defer any changes to the asset allocation until the ALM process concluded, and the board could make its final decision on the asset allocation in November 2021.

On November 17, 2021, the board adopted a new strategic asset allocation. The new asset allocation along with the new capital market assumptions, economic assumptions and administrative expense assumption support a discount rate of 6.90% (net of investment expense but without a reduction for administrative expense) for financial reporting purposes. This includes a reduction in the price inflation assumption from 2.50% to 2.30% as recommended in the November 2021 CalPERS Experience Study and Review of Actuarial Assumptions. This study also recommended modifications to retirement rates, termination rates, mortality rates and rates of salary increases that were adopted by the board. These new assumptions will be reflected in the GASB 68 accounting valuation reports for the June 30, 2022, measurement date.

SENSITIVITY OF THE NET PENSION LIABILITY (ASSET) TO CHANGES IN THE DISCOUNT RATE

The following presents the Electric Utility's proportionate share of the net pension liability of the Plan, calculated using the discount rate of 6.90% (measurement date June 30, 2022) and 7.15% (measurement date June 30, 2021), as well as what the Electric Utility's proportionate share of the net pension liability would be if it was calculated using a discount rate that is 1-percentage point lower or 1-percentage point higher than the current rate:

	Measurement Date June 30, 2022			Measurement Date June 30, 2021		
	Discount Rate -1% (5.90%)	Current Discount Rate (6.90%)	Discount Rate +1% (7.90%)	Discount Rate -1% (6.15%)	Current Discount Rate (7.15%)	Discount Rate +1% (8.15%)
Electric Utilitiy's proportionate share of the Plan's net pension liability	$ 103,174	$ 38,748	$ (14,155)	$ 35,141	$ (26,219)	$ (76,749)

Detailed information about the Plan's fiduciary net position is available in the separately issued CalPERS financial reports.

7. OTHER POST-EMPLOYMENT BENEFITS (OPEB)

PLAN DESCRIPTION

The City's defined benefit OPEB plan, Retiree Health Plan, provides continuation of medical (including prescription drugs) and dental coverage benefits to retirees and surviving spouses in the form of an implied rate subsidy. The Retiree Health Benefits plan is a single employer defined benefit OPEB plan administered by the City. No assets are accumulated in a trust that meets the criteria in paragraph 4 of GASB Statement No. 75.

BENEFITS PROVIDED

Eligibility for continuation of coverage requires retirement from the City and CalPERS with at least 5 years of City service. The retiree is responsible for 100% of the premium cost for coverage, which is based on the blended experience of both the active and retired employees. The City is not required by law or contractual agreement to provide funding other than the pay-as-you-go amount necessary to provide current benefits to eligible retirees and beneficiaries. Retiree and spousal coverage terminate when the retiree becomes covered under another employer health plan, or when the retiree reaches Medicare eligibility age, which is currently age 65. However, retiree benefits continue to the surviving spouse if the retiree elects the CalPERS survivor annuity.

As of measurement date June 30, 2022 and 2021, the following employees, City-wide, were covered by the benefit terms:

	Measurement Date June 30, 2022	Measurement Date June 30, 2021
Inactive plan members or beneficiaries currently receiving benefits	206	206
Inactive plan members entitled to but not yet receiving benefits	-	-
Active plan members	2,014	2,014

7. OTHER POST-EMPLOYMENT BENEFITS (OPEB) (CONTINUED)

ACTUARIAL ASSUMPTIONS

The total OPEB liability was determined by actuarial valuation as of June 30, 2022 and 2021 using the following actuarial assumptions:

	Miscellaneous - Current Year	Miscellaneous - Prior Year
Valuation Date	June 30, 2021	June 30, 2021
Measurement Date	June 30, 2022	June 30, 2021
Actuarial Cost Method	Pay-as-you-go for implicit rate subsidy	Pay-as-you-go for implicit rate subsidy
Actuarial Assumptions		
Discount Rate	Bond Buyer 20 Index at June 30, 2022 resulting in a rate of 3.54%	Bond Buyer 20 Index at June 30, 2021 resulting in a rate of 2.16%
Inflation Rate	2.50% per annum	2.75% per annum
Payroll Increases	2.75% per year. Since benefits do not depend on salary (as they do for pensions), this assumption is only used to determine the accrual pattern of the Actuarial Present Value of Projected Benefit Payments.	2.75% per year. Since benefits do not depend on salary (as they do for pensions), this assumption is only used to determine the accrual pattern of the Actuarial Present Value of Projected Benefit Payments.
Mortality	2017 CalPERS Retiree Mortality Table for the appropriated population	2017 CalPERS Retiree Mortality Table for the appropriated population
Healthcare Trend Rates	Medical trend in future years has been updated to 4.00% for all years from 6.25% tiered down by 0.25% per year to 4.50% in all future years.	Medical trend in future years has been updated to 4.00% for all years from 6.25% tiered down by 0.25% per year to 4.50% in all future years.

CHANGES OF ASSUMPTIONS

In 2022, the discount rate was changed from 2.16% to 3.54%.

SENSITIVITY OF TOTAL OPEB LIABILITY TO CHANGES IN HEALTHCARE COST TREND RATES

The following presents the Electric Utility's proportionate share of the City's total OPEB liability, calculated using the healthcare trend rate of 4.00% for the measurement date as of June 30, 2022 and 2021, as well as what the Electric Utility's total OPEB liability would be if it was calculated using a healthcare cost trend rate that is 1-percentage-point lower or 1-percentage-point higher than the current rate:

	Measurement Date June 30, 2022			Measurement Date June 30, 2021		
	1% Decrease	Current healthcare cost trend rate 4%	1% Increase	1% Decrease	Current healthcare cost trend rate 4%	1% Increase
Electric Utility's proportionate share of the total OPEB liability	$ 8,627	$ 9,837	$ 11,213	$ 9,205	$ 10,460	$ 11,950

7. OTHER POST-EMPLOYMENT BENEFITS (OPEB) (CONTINUED)

SENSITIVITY OF TOTAL OPEB LIABILITY TO CHANGES IN DISCOUNT RATES

The following presents the Electric Utility's proportionate share of the City's total OPEB liability, calculated using the discount rate of 3.54% and 2.16% for measurement dates of June 30, 2022 and 2021 respectively, as well as what the Electric Utility's total OPEB liability would be if it was calculated using a discount rate that is 1-percentage-point lower or 1-percentage-point higher than the current rate:

	Measurement Date June 30, 2022			Measurement Date June 30, 2021		
	1% Decrease (2.54%)	Current Discount Rate (3.54%)	1% Increase (4.54%)	1% Decrease (1.16%)	Current Discount Rate (2.16%)	1% Increase (3.16%)
Electric Utility's proportionate share of the total OPEB liability	$ 10,782	$ 9,837	$ 9,169	$ 11,354	$ 10,460	$ 9,632

CHANGE IN TOTAL OPEB LIABILITY

For fiscal years ended June 30, 2023 and 2022, the Electric Utility recognized total OPEB expense of $431 and $530 respectively. The following table shows the change in the Electric Utility's proportionate share of the City's total OPEB liability for the year ended June 30, 2023 (measurement date June 30, 2022) and the year ended June 30, 2022 (measurement date June 30, 2021):

June 30, 2023	Net OPEB Liability	Proportion of the Plan
Proportion - Reporting date June 30, 2023 (Measurement Date June 30, 2022)	$ 9,837	21.63 %
Proportion - Reporting date June 30, 2022 (Measurement Date June 30, 2021)	10,460	21.45 %
Changes - Increase / (Decrease)	(623)	0.18 %
June 30, 2022		
Proportion - Reporting date June 30, 2022 (Measurement Date June 30, 2021)	10,460	24.45 %
Proportion - Reporting date June 30, 2021 (Measurement Date June 30, 2020)	11,126	24.28 %
Changes - Increase / (Decrease)	(666)	0.17 %

DEFERRED OUTFLOWS/INFLOWS OF RESOURCES RELATED TO OPEB

At June 30, 2023, the Electric Utility reported deferred inflows of resources related to OPEB from the following sources:

	Deferred Outflows of Resources	Deferred Inflows of Resources
Difference between expected and actual experience	$ 29	$ (649)
Changes of assumptions	1,254	(1,617)
Contributions subsequent to measurement date	309	-
Total	$ 1,592	$ (2,266)

7. OTHER POST-EMPLOYMENT BENEFITS (OPEB) (CONTINUED)

DEFERRED OUTFLOWS/INFLOWS OF RESOURCES RELATED TO OPEB (CONTINUED)

Amounts reported as deferred inflows of resources related to OPEB will be recognized in OPEB expense as follows:

Year Ended June 30		Deferred Outflows/ (Inflows) of Resources
2024	$	(27)
2025		(27)
2026		15
2027		22
2028		22
Thereafter		(988)
Total	$	(983)

8. RESTRICTED NET POSITION

The California Code of Regulations establishes a restriction on the use of proceeds obtained from the sale of greenhouse gas allowances at auctions held pursuant to California's Cap-and-Trade Program. The proceeds are to be used exclusively for the benefit of retail ratepayers of each electrical distribution utility and may not be used for the benefit of entities or persons other than such ratepayers. In addition, the Low Carbon Fuel Standard Program (LCFS) was established and restricts the use of the proceeds obtained from the sale of LCFS credits. The available funds are to be utilized for qualifying projects that support the Electric Utility's customers who are existing and future electric vehicle owners. Accordingly, a reserve for regulatory requirements has been established by restricting assets and reserving a portion of net position. See Note 11 for additional information regarding the Cap-and-Trade Program and the LCFS Program.

Pursuant to applicable bond indentures, a reserve for debt service has been established by restricting assets and reserving a portion of net position. Bond indentures for the Electric Utility's electric revenue and refunding bonds require debt service reserves that equate to the maximum annual debt service required in future years and bond service reserves of three months interest and nine months principal due in the next fiscal year. Variable rate revenue and refunding bonds require 110 percent of the monthly accrued interest to be included in the reserve. Active electric revenue bonds requiring reserves are issues 2008A & C and certain issues have no debt service reserve requirements (2010A, 2011A, 2013A and 2019A).

9. JOINTLY-GOVERNED ORGANIZATIONS

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

On November 1, 1980, the City joined with the Imperial Irrigation District and the cities of Los Angeles, Anaheim, Vernon, Azusa, Banning, Colton, Burbank, Glendale and Pasadena to create the Southern California Public Power Authority (SCPPA) by a Joint Powers Agreement under the laws of the State of California. As of July 2001, the City of Cerritos was admitted as an additional member of SCPPA. The primary purpose of SCPPA is to plan, finance, develop, acquire, construct, operate and maintain projects for the generation and transmission of electric energy for sale to its participants. SCPPA is governed by a Board of Directors, which consists of one representative from each of the members. During fiscal years ended June 30, 2023 and 2022, the Electric Utility paid approximately $21,085 and $21,549, respectively, to SCPPA under various take-or-pay and renewable contracts that are described in greater detail in Note 11. These payments are reflected as a component of production and purchased power and transmission expenses in the financial statements.

POWER AGENCY OF CALIFORNIA

On July 1, 1990, the City joined with the cities of Azusa, Banning and Colton to create the Power Agency of California (PAC) by a Joint Powers Agreement under the laws of the State of California. The City of Anaheim joined PAC on July 1, 1996. The primary purpose of PAC is to take advantage of synergies and economies of scale as a result of the five cities acting in concert. PAC has the ability to plan, finance, develop, acquire, construct, operate and maintain projects for the generation and transmission of electric energy for sale to its participants. PAC is governed by a Board of Directors, which consists 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.

10. JOINTLY-OWNED UTILITY PROJECT - SONGS

The City has a 1.79 percent undivided ownership interest in Units 2 and 3 of SONGS, located south of the City of San Clemente in northern San Diego County. Both Units 2 and 3 of SONGS were permanently retired in June 2013. Consequently, the units are no longer a source of supply for the Electric Utility, but remain associated with certain of its costs, including those associated with the units' shutdown and decommissioning.

The other owners are SCE, with a 78.21 percent interest (including the 3.16 percent interest it acquired from the City of Anaheim in 2006), and San Diego Gas & Electric Company (SDG&E), with a 20.00 percent interest.

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

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

Nuclear Decommissioning. As a result of SCE's decision to permanently retire SONGS Units 2 and 3, the decommissioning phase of the plant began in June 2013. The process of decommissioning the nuclear power plant is expected to take many years and is governed by NRC regulations. According to SCE's decommissioning cost estimate document as of March 2018 in 2017 dollars, total decommissioning costs for Units 2 and 3 were estimated at $4.7 billion, of which the Electric Utility's share was $84 million.

In August 2021, SCE provided the updated decommissioning cost estimate document in 2020 dollars. According to the update, total decommissioning costs for Units 2 and 3 are estimated at $5.2 billion, of which the Electric Utility's share is $93.8 million.

Nuclear Decommissioning Funding and Liability. As of June 30, 2023, the Electric Utility has set aside $47,110 in cash investments with the trustee and $8,644 in a designated decommissioning reserve for the Electric Utility's estimated share of the decommissioning costs. Increases to the funds held for decommissioning liability are from investment earnings. The investment earnings are included in investment income in the Electric Utility's financial statements. An equivalent amount is reflected as decommissioning expense, which is considered part of production and purchased power. Decreases to the funds held for decommissioning liability are from actual funds drawn from the trust for decommissioning costs invoiced by SCE.

On February 23, 2016, the City Council adopted a resolution authorizing the commencement of SONGS decommissioning effective June 7, 2013. This resolution allows the Electric Utility to access the decommissioning trust funds to pay for its share of decommissioning costs. The Electric Utility began drawing decommissioning trust funds to pay for decommissioning costs in the fiscal year ended June 30, 2017. As of June 30, 2023, the Electric Utility has paid to date $45,884 in decommissioning obligations, which have been reimbursed by the trust funds.

As of June 30, 2023 and 2022, decommissioning liability balance was $48,873 and $53,310, respectively, with a portion reflected as current liabilities payable from restricted assets. As a result of the updated SCE decommissioning cost estimate and the increase in the Electric Utility's estimated share, the decommissioning liability was increased by $5.7 million in fiscal year 2022. The offset of this liability increase was recorded as an extraordinary item in fiscal year 2021/22. See Note 13 for additional information.

The Electric Utility no longer provides additional funding to the trustee. However, since the decommissioning cost estimate is subject to a number of uncertainties including the cost of disposal of nuclear waste, site remediation costs, as well as a number of other assumptions and estimates, the Electric Utility will continue to set aside funds in the designated decommissioning reserve of $2,000 per year, as approved by the Board of Public Utilities and City Council.

	Balance As of 6/30/2021	Additions	Reductions	Balance As of 6/30/2022	Additions	Reductions	Balance As of 6/30/2023	Due Within One Year
Nuclear decommissioning liability	$ 50,896	$ 6,555	$ (4,141)	$ 53,310	$ 907	$ (5,344)	$ 48,873	$ 10,227

11. COMMITMENTS

The Electric Utility has 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 central Utah coal-fueled generating station, known as Intermountain Power Project (IPP). 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 and other fixed costs. Such payments are considered a cost of production.

On September 29, 2006, Senate Bill 1368 (SB 1368) was enacted into law. The bill requires electric service providers to limit financial investments in power plants to those that adhere to greenhouse gas performance standards as determined by the Public Utilities Commission. Pursuant to this legislation, the Electric Utility is prohibited from renewing its participation in IPP if it remains a coal fueled generating resource.

In order to facilitate the continued participation in the IPP, the IPA Board issued the Second Amendatory Power Sales Contract, which amended the IPP Contract allowing the plant to replace the coal units with combined cycle natural gas units by July 1, 2025. On June 16, 2015, the City Council approved the IPP renewal agreements, including the Second Amendatory Power Sales Contract and the Renewal Power Sales Contract, and authorized participation in the IPP Repower Project for up to 5 percent in generation capacity or 60 MW. The Second Amendatory Power Sales Contract became effective March 16, 2016.

On January 5, 2017, the Electric Utility executed the Renewal Power Sales Contract and the Electric Utility accepted an offer of 4.167 percent entitlement or 50 MW generation capacity in the IPP Repower Project based on the 1,200 MW designed capacity, which is within the maximum participation level approved by the City Council. The Electric Utility's corresponding Southern Transmission System allocation is 5.278 percent or approximately 127 MW. Further, under the Renewal Power Sales Contract, the Electric Utility had the right to exit from the Repower Project by no later than November 1, 2019, if it is determined that the Repower Project is not cost beneficial to its customers.

On September 11, 2018, the City Council approved “Alternative Repowering” of the IPP Repower Project, which reduced the design capacity of the future plant from 1,200 MW to 840 MW.

On May 7, 2019, the City Council authorized termination of the Renewal Power Sales Contract between the IPA and the Electric Utility effective November 1, 2019, and the Electric Utility's exit from the IPP Repower Project upon the expiration date of the current Power Sales Contract on June 15, 2027, due to numerous uncertainties surrounding the IPP Repower Project.

The Electric Utility is a member of SCPPA, a joint powers agency (see Note 9). 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 take-or-pay 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	5.40 %	12.3 MW	2017	2030
Southern Transmission System	10.20 %	244.0 MW	2027	2027
Mead-Phoenix Transmission	4.00 %	18.0 MW	2020	2030
Mead-Adelanto Transmission	13.50 %	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.

11. COMMITMENTS (CONTINUED)

The outstanding debts associated with the take-or-pay obligations have fixed interest rates, which range from 4.00 percent to 5.00 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:

Debt Service Payment (in thousands) Year Ending June 30,	IPA[1] Intermountain Power Project	SCPPA Southern Transmission System	Total All Projects
2024	$ 3,479	$ 7,125	$ 10,604
2025	2,997	3,261	6,258
2026	2,997	3,257	6,254
2027	4,810	3,253	8,063
2028	-	3,254	3,254
Total	$ 14,283	$ 20,150	$ 34,433

[1] The Electric Utility's contract with IPA expires in 2027. The Electric Utility will not be responsible for the proportionate share of the 2022 Series A and B Revenue bonds after the contract expires.

In addition to debt service, the Electric Utility's entitlements require the payment of fuel costs, operating and maintenance, administrative and general and other miscellaneous costs associated with the generation and transmission facilities discussed above. These costs do not have a similar structured payment schedule as debt service varies each year. The costs incurred for the years ended June 30, 2023 and 2022, are as follows (in thousands):

Fiscal Year	Intermountain Power Project[1]	Palo Verde Nuclear Generating Station[1]	Southern Transmission System	Mead-Phoenix Transmission	Mead-Adelanto Transmission	All Projects
2023	$ 20,344	$ 3,010	$ 3,839	$ 90	$ 461	$ 27,744
2022	$ 19,522	$ 2,930	$ 4,400	$ 57	$ 415	$ 27,324

[1] Excludes variable cost.

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

The Electric Utility has become a Participating Transmission Owner with the California Independent System Operator (CAISO) 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 California's high voltage transmission grid are charged for, and the Electric Utility receives reimbursement for, transmission revenue requirements, including the costs associated with these three transmission projects.

HOOVER UPRATING PROJECT

The Electric Utility's initial entitlement in the Hoover project through SCPPA terminated on September 30, 2017. On August 23, 2016, the City Council approved a 50-year Electric Service Contract (ESC) and an Amended and Restated Implementation Agreement (IA) with the Western Area Power Administration (Western) Bureau of Reclamation for 30 MW of hydroelectric power. The contract with Western is effective as of October 1, 2017. The ESC extended the Electric Utility's 30 MW entitlement in the Hoover project through 2067. The IA is a supplemental agreement to the ESC that establishes administrative, budgetary and project oversight by creating project committees and a process for decision making in plant operations.

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 ($450 million) and participate in the industry's secondary financial protection plan. The secondary financial protection program is the industry's retrospective assessment plan that uses deferred premium charges from every licensed reactor owner if claims and/or costs resulting from a nuclear incident at any licensed reactor in the United States were to exceed the primary nuclear insurance at that plant's site. Effective October 5, 2023,

11. COMMITMENTS (CONTINUED)

NUCLEAR INSURANCE (CONTINUED)

the Act limits liability from third-party claims to approximately $16.5 billion per incident. Under the industry-wide retrospective assessment program provided for under the Act, assessments are limited to $137.6 million per reactor for each nuclear incident occurring at any nuclear reactor in the United States, with payments under the program limited to $24.7 million per reactor, per year, per event to be indexed for inflation every five years. Based on the Electric Utility's interest in Palo Verde, the Electric Utility would be responsible for a maximum assessment of $1.4 million, limited to payments of $0.2 million per incident, per year. If the public liability limit above is insufficient, federal regulations may impose further revenue-raising measures to pay claims, including a possible additional assessment on all licensed reactor operators.

RENEWABLE PORTFOLIO STANDARD (RPS)

On April 12, 2011, the California Renewable Energy Resources Act (SBX1-2) was signed into law by the Governor, which officially created the first set of tiered RPS targets of 20% by 2013, 25% by 2016 and 33% by 2020. SBX1-2 specified that publicly owned utilities must meet these defined targets via interim Compliance Period (CP) targets to achieve the end goal of 33% RPS by December 31, 2020 as follows: CP1 - an average of 20 percent of retail sales during the 3-year period from 2011-2013; CP2 – no less than 25 percent of retail sales by December 31, 2016; and CP3 – no less than 33 percent of retail sales by December 31, 2020. The Riverside Public Utilities Board and City Council approved the RPS Enforcement Program required by SBX1-2 on November 18, 2011 and December 13, 2011, respectively, and further approved the Electric Utility's RPS Procurement Plan (a.k.a. Procurement Policy) implementing the new RPS mandates on May 3, 2013 and May 14, 2013, respectively. The Electric Utility met the procurement requirements of SBX1-2 for CP1 (2011-2013), CP2 (2014-2016), and CP3 (2017-2020). The additional future mandates are expected to be met with resource procurement actions as outlined in the Electric Utility's RPS Procurement Plan. For calendar year 2021, renewable resources provided 45 percent of retail sales requirements.

On October 7, 2015, the Governor signed into law Senate Bill 350 (SB 350) increasing the RPS mandate from 33 percent by 2020 to 50 percent by December 31, 2030. In addition, SB 350 required that an updated RPS Procurement Policy be approved and adopted before January 1, 2019 and be incorporated into the Electric Utility's Integrated Resource Plan. An updated 2018 Renewable Energy Procurement Policy was adopted by the Board and City Council on September 10, 2018 and October 9, 2018, respectively. The Electric Utility expects to be able to substantially meet the increased RPS mandates imposed by SB 350 with the actions described in the updated procurement policy and the portfolio of renewable resources outlined below.

On September 10, 2018, the 100 Percent Clean Energy Act of 2018 (Senate Bill 100) was signed into law by the California Governor. This bill further increases the RPS goals of SBX1-2 and SB 350 while maintaining the 33 percent RPS target by December 31, 2020, but modifying the RPS percentages to be 44 percent by December 31, 2024, 52 percent by December 31, 2027, 60 percent by December 31, 2030, with an end goal of 100 percent of total retail sales of electricity in California generated from eligible renewable energy resources and zero-carbon resources by December 31, 2045. It is expected that the California Energy Commission will have further guidance and enforcement procedures for publicly owned utilities to meet these increased mandates. The Electric Utility will continue to monitor the outcome and impacts of any upcoming workshops and regulations in meeting the new requirements.

In an effort to increase the share of renewables in the Electric Utility's power portfolio, the Electric Utility entered into power purchase agreements (PPA) and power sales agreements (PSA) with various entities described below in general on a "take-and-pay" basis. The contracts in the following tables were executed as part of compliance with RPS mandates.

11. COMMITMENTS (CONTINUED)

RENEWABLE PORTFOLIO STANDARD (RPS) (CONTINUED)

Long-term renewable PPAs and PSAs in operation (dollars in thousands):

Supplier	Type	Maximum Contract[1]		Contract Expiration	Estimated Annual Cost for 2023
Wintec	Wind	1.3	MW	02/19/2024	$ 150
WKN Wagner	Wind	6.0	MW	12/22/2032	1,358
Terraform Power - AP North Lake	Photovoltaic	20.0	MW	08/11/2040	4,942
Onward Energy - Columbia II	Photovoltaic	11.1	MW	12/22/2034	2,314
GlidePath Power Solutions - GPS Cabazon Wind LLC	Wind	39.0	MW	01/01/2025	4,299
Capital Dynamics - Kingbird Solar B, LLC	Photovoltaic	14.0	MW	12/31/2036	2,867
AES - Summer Solar	Photovoltaic	10.0	MW	12/31/2041	1,748
AES - Antelope Big Sky Ranch	Photovoltaic	10.0	MW	12/31/2041	1,748
AES - Antelope DSR 1 Solar	Photovoltaic	25.0	MW	12/19/2036	3,826
Arevon - Tequesquite Landfill Solar	Photovoltaic	7.3	MW	12/31/2040	1,434
Roseburg Forest Products[2]	Biomass	N/A		02/16/2026	179
CalEnergy - Salton Sea Portfolio	Geothermal	86.0	MW	12/31/2039	56,038
Atlantica - Coso Geothermal	Geothermal	10.0	MW	12/31/2041	6,050
Total[3]		239.7	MW		$ 86,953

[1]All contracts are contingent on energy delivered from specific related generating facilities. The Electric Utility has no commitment to pay any amounts except for energy delivered on a monthly basis from these facilities except for any economic curtailments directed by the Electric Utility.

[2]This supply is only available to satisfy SB 859 requirements.

[3]American Renewable Power - Loyalton was excluded due to the contract expiring April 2023 and no capacity received.

Long-term renewable PPAs with expected delivery:

Supplier	Type	Maximum Contract[1]	Expected Delivery	Energy Delivery No Later Than	Contract Term In Years
Atlantica - Coso Geothermal	Geothermal	20.0 MW	01/01/2027	01/01/2027	15
Total		20.0 MW			

[1]All contracts are contingent on energy delivered from specific related generating facilities. The Electric Utility has no commitment to pay any amounts except for energy delivered on a monthly basis from these facilities except for any economic curtailments directed by the Electric Utility.

On May 20, 2003, the Electric Utility and Salton Sea Power LLC (Salton Sea) entered into a ten-year PPA for 20 MW of geothermal energy. On August 23, 2005, the City Council approved an amendment to the PPA that increased the amount of renewable energy available to the Electric Utility from 20 MW to 46 MW effective June 1, 2009 through May 31, 2020.

On May 14, 2013, the City Council approved a new 25-year PPA with CalEnergy, the parent of Salton Sea, for additional renewable geothermal power. The PPA provides power from a portfolio of ten geothermal generating units, instead of a single generating unit, with an increasing amount of delivery that started with 20 MW in 2016, increasing to 40 MW in 2019, and 86 MW in 2020. The initial price under the agreement was $72.85 per megawatt-hour (MWh) in calendar year 2016, which will escalate at 1.5 percent annually for the remaining term of the agreement. Similar to other renewable PPAs, the Electric Utility is only obligated for purchases of energy delivered to the City.

Concurrently, the pricing under the Salton Sea PPA was amended to conform to pricing in the new PPA with CalEnergy through the remaining term of the Salton Sea PPA. The pricing under the Salton Sea PPA increased by approximately $7.57 per MWh, commencing July 1, 2013 to $69.66 per MWh, with an escalation of 1.5 percent annually thereafter, reflecting the exchange of benefits for a substantially lower pricing under the new PPA. The cost increase under the Salton Sea PPA and accrual of the prepayment ended as of May 31, 2020. As of June 30, 2023 and 2022, the Electric Utility's prepayment of future contractual obligations was $12,330 and $12,970, respectively. This prepayment is recorded on the Statements of Net Position as unamortized purchased power, to be amortized over the term of the CalEnergy PPA. The CalEnergy PPA commenced in February 2016. As of June 30, 2023 and 2022, the Electric Utility has recorded $641 and

11. COMMITMENTS (CONTINUED)

RENEWABLE PORTFOLIO STANDARD (RPS) (CONTINUED)

$645, respectively, in amortization related to the unamortized purchased power.

On January 28, 2003, the Electric Utility entered into a 15-year renewable PPA with Wintec Energy, Ltd (Wintec) to purchase all of the energy output generated by Wintec's wind powered electric generating units with capacity up to 5 MW. Due to unforeseen circumstances, Wintec was only able to generate capacity totaling 1.3 MW. On November 15, 2005, the City Council approved an amendment to the original agreement, reducing the capacity to 1.3 MW. The amended contract with Wintec terminated in December 2018, however, on February 12, 2019, the City Council approved an extension to the amended agreement for an additional five years for a reduced price of $35.77 per MWh.

On October 16, 2012, the Electric Utility entered into a 25-year PPA with AP North Lake, LLC (AP North) for 20 MW of solar photovoltaic energy generated by a new facility located in the City of Hemet, California. The AP North Lake Project became fully operational in August 2015. The project is expected to generate 55,000 MWh of renewable energy per year at a levelized cost of $95 per MWh for the term of the PPA. After a series of ownership changes, AP North Lake is now owned by Terraform Power.

On December 20, 2012, the Electric Utility entered into a 20-year PPA with WKN Wagner, LLC (WKN) for up to 6 MW of renewable wind energy and renewable energy credits from the WKN Wagner wind project in Palm Springs, California. WKN is expected to generate 21,000 MWh of renewable energy annually at a levelized cost of $73 per MWh.

On January 17, 2013, the Electric Utility entered into two 25-year PSAs with SCPPA for a combined total of 20 MW of solar photovoltaic energy generated by two facilities to be built in the City of Lancaster by Silverado Power, which later changed its name to sPower after a series of ownership changes. The two projects are referred to as Antelope Big Sky Ranch and Summer Solar, each rated at 20 MW. The Electric Utility has a 50 percent share of the output from each project through SCPPA, which has two 20 MW PPAs with sPower. Summer Solar became commercially operational on July 25, 2016, and Antelope Big Sky Ranch became commercially operational on August 19, 2016. The Electric Utility's share from the two projects is 55,000 MWh of renewable energy per year. The price under the agreements is $71.25 per MWh over the term of the agreements. In 2021, sPower merged with the AES Corporation, resulting in AES becoming the new parent company.

On September 19, 2013, the Electric Utility entered into a 20-year PSA with SCPPA for 14 MW of solar photovoltaic energy generated by a facility to be built by First Solar in Kern County, California. The project is referred to as the Kingbird B Solar Photovoltaic Project, with a nameplate capacity of 20 MW. The Electric Utility has a 70 percent share of the output from the project through SCPPA, which has a 20 MW PPA with Kingbird Solar B, LLC, which was acquired by Capital Dynamics in 2018. The project became commercially operational on April 30, 2016. The Electric Utility's share from the project is approximately 35,000 MWh of renewable energy per year with an all-in price for energy, capacity and environmental attributes of $68.75 per MWh over the term of the agreement.

On September 19, 2013, the Electric Utility entered into a 20-year PSA with SCPPA for 11.1 MW of solar photovoltaic energy generated by a facility to be built by Recurrent Energy in Kern County, California. The project, referred to as Columbia Two Solar Photovoltaic Project, has a nameplate capacity of 15 MW. On March 14, 2014, a Consent and Agreement was entered into by SCPPA consenting to the transfer of ownership of the Columbia Two project from Recurrent Energy to Dominion Resources. The Columbia Two Project completed construction and achieved commercial operation in December 2014. The Electric Utility has a 74.3 percent share (11.1 MW) of the output from the Columbia Two Project through SCPPA, which has a 15 MW PPA with Dominion Resources. The Electric Utility's share of Columbia Two is approximately 33,000 MWh of renewable energy per year with an all-in price for energy, capacity and environmental attributes of $69.98 per MWh over the term of the agreement. In 2021, Onward Energy, LLC became the new parent company of Columbia Two.

On December 6, 2013, the Electric Utility and FPL Energy Cabazon Wind, LLC (Cabazon Wind) entered into a 10-year PPA for 39 MW of renewable wind energy from the Cabazon Wind Energy Center near Cabazon, California. Cabazon Wind is an existing renewable resource that has been in commercial operation since 1999. SCE purchased the output of the facility through December 2014. At the expiration of SCE's contract, Cabazon Wind entered into new interconnection and generation agreements with CAISO and SCE. The developer completed the implementation of the transition to the Electric Utility as of January 1, 2015. Delivery under the PPA commenced on January 1, 2015. The project is expected to generate 71,200 MWh of renewable energy per year with an all-in price for energy, capacity and environmental attributes of $59.30 per MWh over the term of the agreement. In 2018, after it was acquired by GlidePath Power Solutions, FPL Energy Cabazon Wind, LLC changed its name to GPS Cabazon Wind, LLC.

11. COMMITMENTS (CONTINUED)

RENEWABLE PORTFOLIO STANDARD (RPS) (CONTINUED)

On March 11, 2014, the Electric Utility and Solar Star California XXXI, LLC (Solar Star) entered into a 25-year PPA for 7.3 MW of solar photovoltaic energy generated by a facility to be built on the City-owned Tequesquite Landfill. The project was fully commissioned and operational on September 30, 2015 and is expected to generate approximately 15,000 MWh of renewable energy per year. The all-in price for energy, capacity and environmental attributes is $81.30 per MWh, escalating at 1.5 percent annually. In 2018, Capital Dynamics became the new parent company of Solar Star after acquiring it from SunPower. In 2022, Capital Dynamics was acquired by Arevon.

On July 16, 2015, the Electric Utility entered into a 20-year PSA with SCPPA for 25 MW of solar photovoltaic energy generated by sPower's Antelope DSR Solar PV Project in the City of Lancaster, California. The Electric Utility has a 50 percent share of the output from the project through SCPPA, which has a 50 MW PPA with sPower. The project became commercially operational on December 20, 2016. The Electric Utility's share of Antelope DSR Solar is expected to generate approximately 71,000 MWh of renewable energy per year with an all-in price for energy, capacity and environmental attributes of $53.75 per MWh over the term of the agreement. In 2021, sPower merged with the AES Corporation, resulting in AES becoming the new parent company.

On November 16, 2017, the Electric Utility entered into a 5-year PSA with SCPPA for 0.8 MW of biomass energy generated by American Renewable Power (ARP) - Loyalton Biomass Project. The Electric Utility has a 4.48 percent share of the output of the project through SCPPA, which, along with Imperial Irrigation District, Modesto Irrigation District, Sacramento Municipal Utility District, and Turlock Irrigation District, has an 18 MW PPA with ARP-Loyalton. The project began delivery on April 20, 2018. The Electric Utility's share of ARP Loyalton is expected to generate 6,358 MWh of renewable energy per year with an all-in price for energy, capacity and environmental attributes of $97.50 per MWh over the term of the agreement. On February 18, 2020, ARP Loyalton Cogen, LLC filed Chapter 11 bankruptcy. On March 18, 2020, the bankruptcy was converted to Chapter 7. On April 30, 2020, the bankruptcy court approved the sale of the ARP Loyalton project to Sierra Valley Enterprise.

On January 15, 2021, the Electric Utility entered into a 20-year PSA with SCPPA for 10 MW for the first 5 years of the contract and 30 MW for the remaining 15 years of the contract of geothermal energy generated by Atlantica's Coso Geothermal project. The Electric Utility has partnered with the cities of Banning and Pasadena to share SCPPA's contracted capacity. The project began delivery on January 1, 2022. The Electric Utility's share of Coso Geothermal is expected to provide 87,500 MWh annually in the first 5 years of the term and 268,300 MWh in the remainder of the term at an all-in price for energy, capacity, Resource Adequacy, and environmental attributes of $69.00 per MWh over the term of the agreement.

On February 16, 2021, the Electric Utility entered into a 5-year SB 859 Purchase Agreement with Roseburg Forest Products Co for the remaining 0.5 MW of SB 859 compliance. The Electric Utility has a 4.48 percent share of the output of the project along with SCPPA, Modesto Irrigation District, Sacramento Municipal Utility District, and Turlock Irrigation District, for a total capacity of 11 MW with Roseburg. The project began delivery on February 16, 2021. The price for the SB 859 compliant capacity is $46.00 per MWh over the term of the agreement.

CAP-AND-TRADE PROGRAM

Assembly Bill (AB) 32, enacted in 2006, mandated that the California Air Resources Board (CARB) develop regulations for the reduction of greenhouse gas (GHG) emissions to the 1990 levels by the year 2020. Subsequently, Senate Bill (SB 32), enacted in 2016, extended the requirements of AB 32 and codified that it was the State's goal to reduce GHG emissions to 40% below 1990 levels by the year 2020. AB 398 was then enacted in 2017 clarifying that it was the State legislature's intent to continue the Cap-and-Trade Program and regulations until 2030. In January 2013, emission compliance obligations developed by CARB began under the Cap-and-Trade Program (Program). This Program requires electric utilities to have GHG allowances on an annual basis to offset GHG emissions associated with generating electricity. To ease the transition and mitigate the rate impacts to retail customers, CARB will allocate certain amounts of GHG allowances at no cost to electrical distribution utilities. The Electric Utility's free allocation of GHG allowances is expected to be sufficient to meet the Electric Utility's direct GHG compliance obligations.

At times, the Electric Utility may have allocated allowances in excess of its compliance obligations that can be sold into the CARB quarterly auctions. In fiscal years ended June 30, 2023 and 2022, the Electric Utility received $18,317 and $14,960, respectively, in proceeds related to the sale of the GHG allowances, which are included on the Statements of Revenues, Expenses and Changes in Net Position as other operating revenue. The Electric Utility has established a restricted

11. COMMITMENTS (CONTINUED)

CAP-AND-TRADE PROGRAM (CONTINUED)

Regulatory Requirement reserve to comply with regulatory restrictions and governing requirements related to the use of the GHG proceeds. The available funds are to be utilized for qualifying projects, consistent with the goals of AB 32 to benefit the retail ratepayers. The balance in the Regulatory Requirement reserve was $21,707 and $16,366 as of June 30, 2023 and 2022, respectively.

The Electric Utility also purchases GHG allowances, which can be used in future periods for GHG compliance regulations. The balance of purchased GHG allowances was $1,464 and $485 as of June 30, 2023 and 2022, and is recorded as inventory on the Statements of Net Position.

LOW CARBON FUEL STANDARD PROGRAM

Assembly Bill (AB) 32, enacted in 2006, mandated that the California Air Resources Board (CARB) develop regulations for the reduction of greenhouse gas (GHG) emissions to the 1990 levels by the year 2020. Subsequently, Senate Bill (SB 32), enacted in 2016, extended the requirements of AB 32 and codified that it was the State's goal to reduce GHG emissions to 40% below 1990 levels by the year 2020. Similar to the Cap-and-Trade Program, the Low Carbon Fuel Standard (LCFS) Program is a key component of the market mechanisms authorized by these bills to achieve the State's GHG emissions reduction goals. The LCFS regulation was initially approved by CARB in 2009. The program then underwent some litigation in the State of California and the regulation was re-adopted in 2015 with modifications and went into effect in 2016. LCFS seeks to reduce the carbon intensity (CI) of fuels used for transportation by establishing an annual CI target. Fuels that have a CI greater than the target have a compliance obligation and are required to turn in LCFS credits; fuels with a CI lower than the target may generate credits.

Electricity is considered a fuel subject to the program when it is used as a transportation fuel in electric vehicles. However, because the CI of electricity is substantially lower than the annual CI targets under the program, electricity is a fuel that generates LCFS credits and participation in the Program is voluntary. The City opted into the LCFS program in March 2018 and began generating LCFS credits for the first quarter of 2018. These credits are associated with two sources – unmetered electricity used to charge residents' electric vehicles at their homes (residential base credits) and from electric forklifts charging at private businesses (forklift credits). CARB calculates the credits that the Electric Utility receives and the Electric Utility submits reports quarterly to receive the credits.

The LCFS regulation was amended in 2018 and required that electric utilities that have opted into the LCFS Program participate in and manage a statewide point-of-sale rebate program for new electric vehicles. This program is called the California Clean Fuel Reward Program (CFR) and the City joined the program in May 2020. To fund the program, electric utilities are required to contribute proceeds received from the sales of residential base credits beginning with the credits the Electric Utility received in Q4 2019 (generated from electricity used for transportation in Q2 2019). Residential base credits the Electric Utility received prior to that time are not subject to the contribution requirements. Additionally, a "start-up" contribution from proceeds was required to be submitted by January 31, 2021. After the initial deposit of funds in November 2020, deposits to the CFR program are required by March 31 annually.

In fiscal years ended June 30, 2023 and 2022, the Electric Utility's proceeds from the sale of LCFS credits was $683 and $1,047, respectively. These proceeds are included on the Statements of Revenues, Expenses and Changes in Net Position as other operating revenue. The Electric Utility has established a restricted Regulatory Requirement reserve to comply with regulatory restrictions and governing requirements related to the use of the LCFS proceeds. The available funds are to be utilized for qualifying programs that support the Electric Utility's customers who are existing and future electric vehicle owners. Total expenses for qualifying programs as of June 30, 2023 and 2022 was $194 and $210, respectively. The balance in the Regulatory Requirement reserve as of June 30, 2023 and 2022 was $3,795 and $3,233, respectively.

CONSTRUCTION COMMITMENTS

As of June 30, 2023, the Electric Utility had commitments (encumbrances) of approximately $25,674 with respect to ongoing capital projects, of which $16,623 is expected to be funded by bonds, $7,676 to be funded by unrestricted cash reserves, and $1,375 to be funded by restricted cash reserves.

FORWARD PURCHASE/SALE AGREEMENTS

In order to meet seasonal energy needs and summer peaking requirements, the Electric Utility contracts on a monthly and/or quarterly basis for the purchase or sale of natural gas, electricity and/or capacity products on a one to four year

11. COMMITMENTS (CONTINUED)

FORWARD PURCHASE/SALE AGREEMENTS (CONTINUED)

forward time horizon. As of June 30, 2023, the Electric Utility has net natural gas and electricity commitments for fiscal year 2024 and thereafter of approximately $112,355, with a market value of $112,807.

12. LITIGATION

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. Contractual and litigation matters of the Electric Utility relating to SONGS are contained in Note 10.

On September 12, 2018, a petition for writ of mandate entitled Parada v. City of Riverside ("Parada II") was filed against the City seeking to invalidate, rescind and void, under Proposition 26, the Electric System's rates approved by City Council on May 22, 2018, which took effect on January 1, 2019, by challenging the portion of the electric rates that are attributable to the General Fund. The petition did not seek any monetary relief from the General Fund. The trial court divided the case into two stages for hearings: a liability phase and a damages phase. On April 17, 2020, the Court in the liability phase of Parada II litigation entered a tentative ruling finding the City's electric rates attributable to the General Fund transfer violate Article XIII C of the California Constitution. The formal hearing on the matter took place on June 5, 2020, but the Court asked for further briefing on the issue of whether or not the plaintiffs failed to exhaust their administrative remedies. On October 9, 2020, the Court confirmed its tentative ruling and entered an order denying the City's request for interlocutory remand. The court had set a hearing for February 24, 2021, to set a briefing schedule for determining appropriate remedies/damages in the case. The City expected the second phase of the trial relating to plaintiffs' available remedies to occur in the second quarter of 2021.

The ruling by the Court in Parada II was anticipated to likely have a material adverse impact on the City's General Fund. The General Fund receives approximately $40 million annually (up to the maximum amount of 11.5% of Electric Fund revenues) from the Electric Fund. Based on the Court's order in the liability phase of the trial, approximately $19-32 million of the General Fund transfer is potentially attributable to rate payer revenue that was not approved by the voters. However, that amount will be determined during the damages phase of the trial. Additionally, the City might have been required to refund rate payers for the portions of the rates that were determined to violate Article XIII C of the California Constitution from the date the writ of mandate was filed. However, the trial court did not issue any ruling as to what the amount of any damages would be.

Based on the Court's order in the liability phase of the trial, the City estimated that the amount of a refund would be $19 to $32 million per year, beginning January 1, 2019, until date of settlement or issuance of a final, non-appealable judgment by the trial court after anticipated appeals are resolved. This amount could vary depending upon whether or not the City decides to repeal and replace the challenged rates pending appeal.

On May 17, 2021, the City and the Paradas entered into a conditional settlement agreement. This settlement was conditioned on: (1) the Riverside City Council's placement of a ballot measure on City ballots in November 2021 to approve the City's General Fund Transfer practices as a general tax ("Ballot Measure"); and (2) voter approval of the Ballot Measure. The Riverside City Council placed the Ballot Measure on the ballot for the November 2, 2021 election. The Parties stayed the Parada lawsuit until certification of the results of the Ballot Measure. If voters approved the Ballot Measure, the City would refund to customers of its electric utility an amount equal to $24 million less the amount awarded to Plaintiffs' counsel in fees, paid over a five year period beginning no later than February 1, 2022.

If voters did not approve the Ballot Measure, this litigation would then resume.

On or about September 16, 2021, a petition for writ of mandate entitled Riversiders Against Increased Taxes v. City of Riverside, et al. ("RAIT lawsuit") was filed against the City challenging the Ballot Measure on the grounds that the Ballot Measure cannot be adopted at the November 2021 election because that election is a "special" election and under Proposition 218, a ballot measure to impose a general tax can only be submitted to voters at a general election. On November 9, 2021, the court set a trial date for the RAIT lawsuit for January 7, 2022 and ordered a stay of the certification of the Ballot Measure Election results pending the January 7th hearing but did not otherwise delay or cancel the election for the Ballot Measure.

The election was held on November 2, 2021, and the Measure C was approved by voters, with 54.52% voting in favor.

12. LITIGATION (CONTINUED)

On April 26, 2022 the RAIT lawsuit trial court determined that the November 2021 election was a “special election” rather than a “general election” and therefore did not comply with Proposition 218. The RAIT lawsuit trial court further ruled that it lacked power to enjoin the certification of election results or to otherwise invalidate the election. Both sides have since appealed that ruling. The appeals have been fully briefed as of June 26, 2023. No date for oral argument has been set.

On May 12, 2022, the City and the Paradas amended the May 17, 2021 Settlement Agreement, with the following additional terms: (a) City agreed to start making refunds to ratepayers by October 1, 2022; (b) if the City prevailed in the appeal of the trial court’s decision in the RAIT lawsuit, no additional refund would be due to the ratepayers; (c) if the City did not prevail in the appeal of the trial court’s decision in the RAIT lawsuit, an additional refund would be implemented in the amount of $705,882 per month, from November, 2021 up to when the City either (i) sets new electric rates; (ii) voters approve a valid ballot measure for the GFT or (iii) the City otherwise stops collecting the electric GFT. The Parada lawsuit was dismissed on May 13, 2022.

The City Council adopted a resolution certifying the results of the Measure C election on July 19, 2022. The plaintiffs from the RAIT lawsuit sought to intervene in the Parada lawsuit and set aside this dismissal. On August 3, 2022, the Parada trial court refused to set aside the dismissal. The City has now begun to implement the settlement agreement.

13. EXTRAORDINARY ITEM

In fiscal year 2021/22, SCE provided the 2020 Decommissioning Cost Estimate report, which projected a material increase in costs for the Electric Utility over the life of the SONGS decommissioning project. As a result, it was determined that the decommissioning liability be increased. The increase in the decommissioning liability of $5,748 was reported as an extraordinary item on the Statements of Revenue, Expenses and Changes in Net Position as of June 30, 2022. For additional information related to SONGS, refer to Note 10.

14. LEASES AND SUBSCRIPTION-BASED INFORMATION TECHNOLOGY ARRANGEMENTS

For the year ended June 30, 2022, the financial statements included the adoption of GASB Statement No. 87, *Leases*. The primary objective of this statement is to enhance the relevance and consistency of information about governments' leasing activities. This statement establishes a single model for lease accounting based on the principle that leases are financings of the right to use an underlying asset. Under this statement, a lessee is required to recognize a lease liability and a lease asset, and a lessor is required to recognize a lease receivable and a deferred inflow of resources. For additional information, refer to the disclosures below.

For the year ended June 30, 2023, the financial statements include the adoption of GASB Statement No. 96, *Subscription-Based Information Technology Agreements* (SBITA). This Statement defines a SBITA as a contract that conveys control of the right to use another party's information technology software, alone or in a combination with tangible capital assets, as specified in a contract for a period of time in an exchange or exchange-like transaction. For additional information, refer to the disclosures below.

LEASES PAYABLE

The Electric Utility has 23 leases as Lessee for the use of various pieces of machinery and equipment as of the end of the fiscal year. The Electric Utility is required to make principal and interest payments through fiscal year 2026. An initial lease liability was recorded in the amount of $625. As of June 30, 2023, the value of the lease liability is $362. The leases have an interest rate of 0.52%. The value of the lease assets as of June 30, 2023 is $628 with accumulated amortization of $273 and is shown on the Asset Class activities table found below.

14. LEASES AND SUBSCRIPTION-BASED INFORMATION TECHNOLOGY ARRANGEMENTS (CONTINUED)

LEASES PAYABLE (CONTINUED)

Asset Class	Amount of Lease Assets by Major Classes of Underlying Asset: Lease Asset Value	Accumulated Amortization
Building	$ 348	$ (149)
Machinery and Equipment	280	(124)
Total	$ 628	$ (273)

Fiscal Year	Principal Payments	Interest Payments	Total Payments
2024	$ 137	$ 2	$ 139
2025	136	1	137
2026	89	-	89
Total	$ 362	$ 3	$ 365

LEASES RECEIVABLE

The Electric Utility has 11 leases as a Lessor for the use of various pieces of building and equipment as of the end of the fiscal year. The terms range from 6 to 30 years beginning on the contract commencement date. An initial lease receivable was recorded in the amount of $1,328. As of June 30, 2023, the value of the lease receivable is $11,766. The leases have interest rates ranging from 0.52% to 1.68%. The value of the deferred inflow of resources as of June 30, 2023 was $11,394, and the Electric Utility recognized lease revenue of $1,583 during the fiscal year.

Fiscal Year	Principal Payments	Interest Payments	Total Payments
2024	$ 1,359	$ 131	$ 1,490
2025	1,412	118	1,530
2026	1,365	106	1,471
2027	1,436	94	1,530
2028	1,165	83	1,248
2029-2033	2,416	306	2,722
2034-2038	1,819	138	1,957
2039-2043	794	15	809
Total	$ 11,766	$ 991	$ 12,757

14. LEASES AND SUBSCRIPTION-BASED INFORMATION TECHNOLOGY ARRANGEMENTS (CONTINUED)

SUBSCRIPTION-BASED INFORMATION TECHNOLOGY ARRANGEMENTS PAYABLE

The Electric Utility has 2 subscription-based information technology arrangement (SBITA) for the use of various software as of the end of the fiscal year. The Electric Utility is required to make principal and interest payments through fiscal year 2025. An initial lease liability was recorded in the amount of $32. As of June 30, 2023, the value of the subscription liability was $49. The subscriptions have an interest rate of 0.52%. The value of the subscription asset as of June 30, 2023 is $93 with accumulated amortization of $43.

Fiscal Year	Principal	Interest	Total Payments
2024	$ 42	$ -	$ 42
2025	7	-	7
Total	**$ 49**	$ -	**$ 49**

ELECTRIC UTILITY:
KEY HISTORICAL OPERATING DATA

Fiscal Year	2022/23	2021/22	2020/21	2019/20	2018/19
POWER SUPPLY MEGAWATT-HOURS (MWH)					
Nuclear					
Palo Verde	101,500	101,100	99,800	100,900	100,200
Coal					
Intermountain Power	460,400	453,900	539,200	551,300	677,900
Hoover (Hydro)	22,900	28,000	30,600	27,000	28,600
Gas					
Springs	1,400	600	1,800	700	400
RERC	76,000	54,400	83,800	68,200	93,900
Clearwater	15,200	13,000	9,800	8,600	13,700
Renewable resources	1,010,800	1,272,700	1,029,300	922,800	835,500
Market purchases	551,700	359,200	468,000	558,500	511,500
Total	**2,239,900**	**2,282,900**	**2,262,300**	**2,238,000**	**2,261,700**
System peak megawatt (MW)	647.8	575.9	630.3	587.2	610.9
ELECTRIC USE					
Number of meters as of year end					
Residential	100,054	99,731	99,226	98,930	98,322
Commercial[3]	12,026	11,922	11,817	11,598	11,537
Industrial[3]	622	625	616	581	570
Other	49	50	52	52	51
Total	**112,751**	**112,328**	**111,711**	**111,161**	**110,480**
Millions of kilowatt-hours (kWh) sales					
Residential	786	759	783	723	722
Commercial[3]	440	443	430	442	460
Industrial[3]	920	923	891	931	947
Other	15	19	18	18	21
Subtotal	**2,161**	**2,144**	**2,122**	**2,114**	**2,150**
Wholesale[2]	14	2	-	1	-
Total	**2,175**	**2,146**	**2,122**	**2,115**	**2,150**
ELECTRIC FACTS					
Average annual kWh per residential customer	7,873	7,632	7,907	7,322	7,375
Average price (cents/kWh) per residential customer	$ 17.88	$ 17.71	$ 17.03	$ 16.77	$ 16.11
Debt service coverage ratio (DSC)[4,5,6,7]	2.01	2.03	1.99	2.62	2.24
Operating income as a percent of operating revenues	10.0 %	18.6 %	9.6 %	12.1 %	11.4 %
Employees[1]	473	473	468	466	475

1 Approved positions.

2 For fiscal years 18/19 and 20/21, wholesale kWh was less than 1 million kWh. Increase in fiscal year 22/23 was due to a transmission constraint requiring the power the Electric Utility was scheduled to receive to be resold.

3 Changes in fiscal years 18/19, 19/20 and 20/21 reflect reclassification of certain Industrial and Commercial accounts related to contract accounts.

4 Interest expense used to calculate DSC is net of federal subsidy on Build America Bonds.

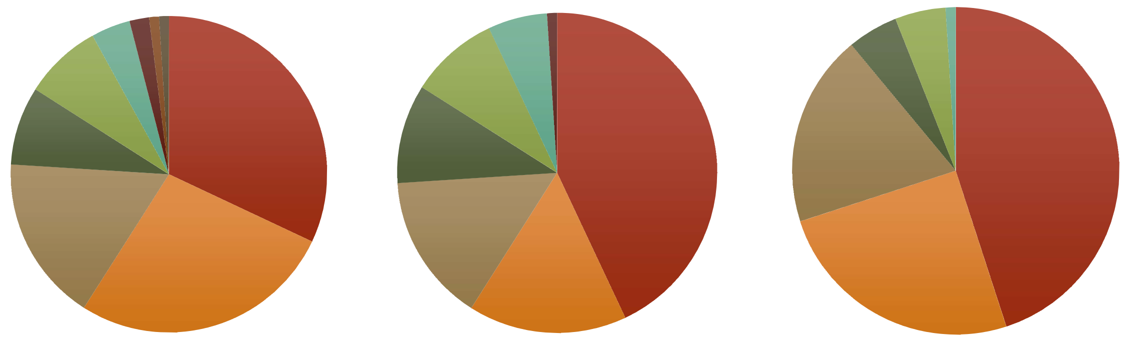
5 Does not include GASB 68 - Accounting and Financial Reporting for Pension non-cash adjustments of ($1,308), ($16,425), $9,682, $3,364, and ($1,323) for fiscal years 22/23 through 18/19, respectively.

6 Does not include GASB 75 - Accounting and Financial Reporting for Post-employment Benefits Other than Pensions non-cash adjustments of $431, $530, $183, $490, and $300 for fiscal years 22/23 through 18/19, respectively.

7 Includes GASB 87 Leases net revenue adjustment of $247 and $134 for fiscal years 22/23 and 21/22, respectively.

2022/2023 ELECTRIC REVENUE AND RESOURCES

SOURCE OF REVENUE | **DISTRIBUTION OF REVENUE** | **ENERGY RESOURCES****



Source of Revenue
- Residential Sales 32¢
- Industrial Sales 27¢
- Commercial Sales 17¢
- Transmission Revenue 8¢
- Other Revenue 8¢
- Use of Reserves 4¢
- Public Benefit Programs 2¢
- Other Sales 1¢
- Investment Income 1¢

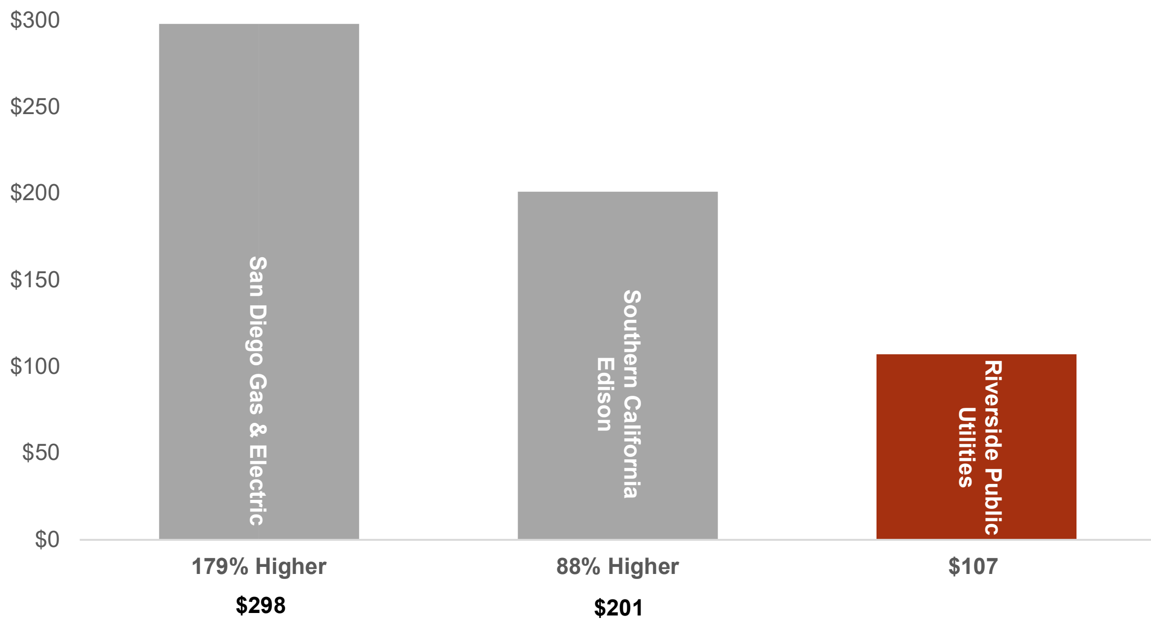
Distribution of Revenue
- Production 43¢
- Distribution 16¢
- Transmission 15¢
- Debt Service 10¢
- Transfers to the City's General Fund* 9¢
- Additions & Replacements to the System 6¢
- Public Benefit Programs 1¢

*Based on transfer of 11.5% of fiscal year 2021/2022 gross operating revenues including adjustments.

Energy Resources
- Renewables 45%
- Market Purchases 25%
- Coal 19%
- Nuclear 5%
- Gas 5%
- Hydropower 1%

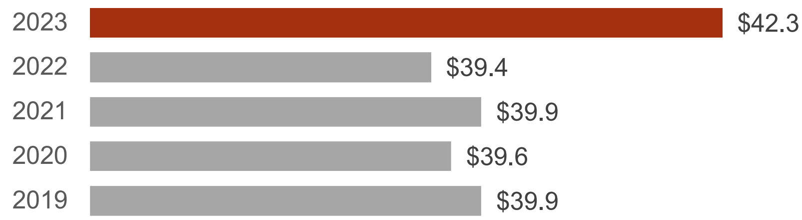
**Energy Resources are based on calendar year 2022 as filed with the California Energy Commission

ELECTRIC RATE COMPARISON - 600 KWH PER MONTH (AS OF JUNE 30, 2023)

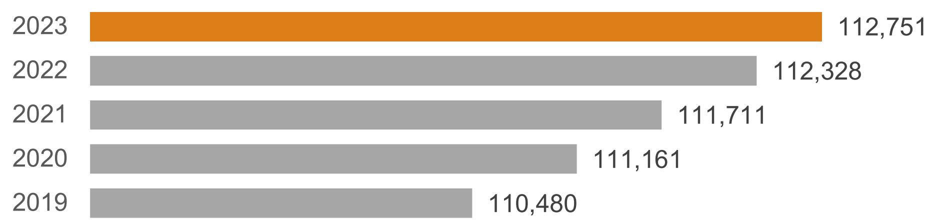


ELECTRIC KEY OPERATING INDICATORS

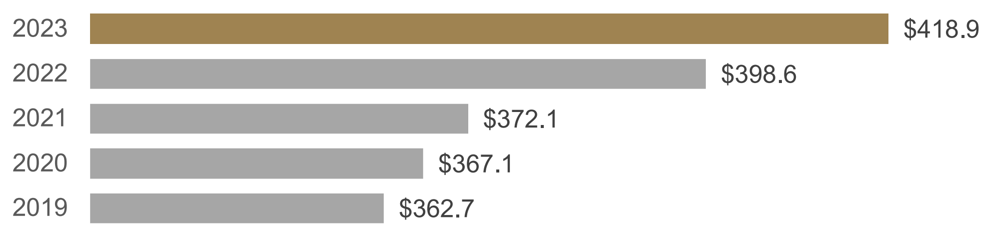
General Fund Transfer (In Millions)



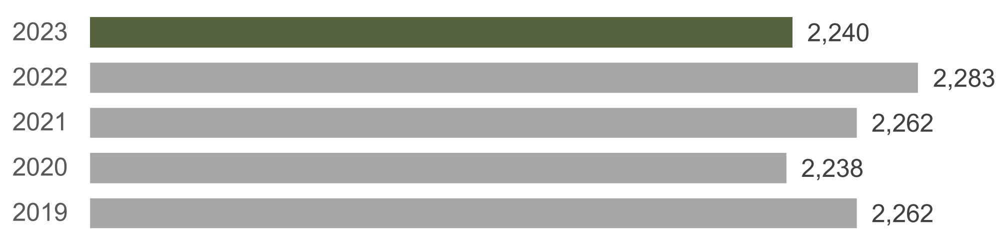
Number of Meters At Year End



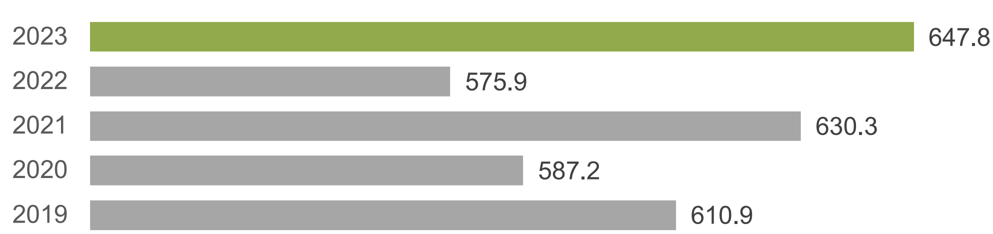
Total Operating Revenue (In Millions)



Production (In Million Kilowatt-Hours)



Peak Day Demand (In Megawatts)



ELECTRIC FACTS AND SYSTEM DATA

Established	1895
Service Area Population	313,676
City Service Area Size (square miles)	81.5

System Data

Transmission Lines (circuit miles)	99.2
Distribution Lines (circuit miles)	1,355
Number of Substations	16
2022-23 Peak Day (megawatts) Highest Single Hourly Use: 09/07/2022, 4pm, 99.3 degrees	648
Historical Peak (megawatts) Highest Single Hourly Use: 09/07/2022, 4pm, 99.3 degrees	648

Bond Ratings

Fitch Ratings	AA-
S & P Global Ratings	AA-

OUR
WATER

RIVERSIDE PUBLIC UTILITIES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INDEPENDENT AUDITORS' REPORT

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

Report on the Audit of the Financial Statements

Opinion

We have audited the accompanying financial statements of the Water Utility Enterprise Fund (Water Utility) of the City of Riverside, California, (the City) as of and for the years ended June 30, 2023 and the related notes to the financial statements, which collectively comprise the Water Utility's financial statements as listed in the table of contents.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Water Utility Enterprise Fund of the City of Riverside, as of June 30, 2023 and the respective changes in financial position and cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Basis for Opinion

We conducted our audit 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. Our responsibilities under those standards are further described in the Auditor's Responsibilities for the Audit of the Financial Statements section of our report. We are required to be independent of the Water Utility and to meet our other ethical responsibilities, in accordance with the relevant ethical requirements relating to our audit. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinions.

Emphasis of Matter

As discussed in Note 1, the financial statements present only the Water Utility Enterprise Fund of the City of Riverside and do not purport to, and do not present fairly the financial position of the City as of June 30, 2023, the changes in its financial position, or, where applicable, its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America. Our opinion is not modified with respect to this matter.

Change in Accounting Principle

As described in Note 1 to the financial statements, in the fiscal year ended June 30, 2023, the Water Utility adopted new accounting guidance, GASB Statement No. 96, *Subscription-Based Information Technology Arrangements*. Our opinion is not modified with respect to this matter.

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

Responsibilities of Management for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with accounting principles generally accepted in the United States of America, and for the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is required to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the Water Utility's ability to continue as a going concern for twelve months beyond the financial statements date, including any currently known information that may raise substantial doubt shortly thereafter.

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinions. Reasonable assurance is a high level of assurance but is not absolute assurance and therefore is not a guarantee that an audit conducted in accordance with generally accepted auditing standards and *Government Auditing Standards* will always detect a material misstatement when it exists. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control. Misstatements are considered material if there is a substantial likelihood that, individually or in the aggregate, they would influence the judgment made by a reasonable user based on the financial statements.

In performing an audit in accordance with generally accepted auditing standards and *Government Auditing Standards*, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Water Utility's internal control. Accordingly, no such opinion is expressed.

- Evaluate the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluate the overall presentation of the financial statements.

We are required to communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit, significant audit findings, and certain internal control-related matters that we identified during the audit.

Required Supplementary Information

Accounting principles generally accepted in the United States of America require that the management's discussion and analysis as listed on the table of contents, presented to supplement the basic financial statements. Such information is the responsibility of management and, although not a part of the basic financial statements, is required by the Governmental Accounting Standards Board who considers it to be an essential part of financial reporting for placing the basic financial statements in an appropriate operational, economic, or historical context. We have applied certain limited procedures to the required supplementary information in accordance with auditing standards generally accepted in the United States of America, which consisted of inquiries of management about the methods of preparing the information and comparing the information for consistency with management's responses to our

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

inquiries, the basic financial statements, and other knowledge we obtained during our audit of the basic financial statements. We do not express an opinion or provide any assurance on the information because the limited procedures do not provide us with sufficient evidence to express an opinion or provide any assurance.

Summarized Comparative Information

We have previously audited the financial statements of the Water Electric Utility for the year ended June 30, 2022, and expressed an unmodified audit opinion on those financial statements in our report dated January 26, 2023. In our opinion, the summarized comparative information presented herein as of and for the year ended June 30, 2022 is consistent, in all material respects, with the audited financial statements from which it has been derived.

Other Information

Management is responsible for the other information included in the annual report. The other information comprises the statistical section but does not include the basic financial statements and our auditor's report thereon. Our opinions on the financial statements does not cover the other information, and we do not express an opinion or any form of assurance thereon.

In connection with our audit of the financial statements, our responsibility is to read the other information and consider whether a material inconsistency exists between the other information and the financial statements, or the other information otherwise appears to be materially misstated. If, based on the work performed, we conclude that an uncorrected material misstatement of the other information exists, we are required to describe it in our report.

Other Reporting Required by *Government Auditing Standards*

In accordance with *Government Auditing Standards*, we have also issued our report dated November 8, 2023, on our consideration of the City's internal control over financial reporting and on our tests of its compliance with certain provisions of laws, regulations, contracts, and grant agreements and other matters. The purpose of that report is solely 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 effectiveness of the City's internal control over financial reporting or on compliance. That report is an integral part of an audit performed in accordance with *Government Auditing Standards* in considering the City's internal control over financial reporting and compliance.

Lance, Soll & Lunghard, LLP

Brea, California
November 8, 2023

WATER UTILITY:
MANAGEMENT'S DISCUSSION AND ANALYSIS

As management of Riverside Public Utilities, a department of the City of Riverside (the City), we offer the readers this narrative overview and analysis of the 2022-23 financial report for the periods ended June 30, 2023 and 2022 for Riverside's Water Utility (Water 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 98 of this report. All amounts, unless otherwise indicated, are expressed in thousands of dollars.

FINANCIAL HIGHLIGHTS

- Governmental Accounting Standards Board No. 96, Subscription-Based Information Technology Agreements (GASB 96) - For the year ended June 30, 2023, the financial statements include the adoption of GASB Statement No. 96, Subscription-Based Information Technology Agreements (SBITA). This Statement defines SBITA as a contract that conveys control of the right to use another party's information technology software, alone or in a combination with tangible capital asset, as specified in a contract for a period of time in an exchange or exchange-like transaction. For additional information, refer to Notes 1, 3, and 11.
- In December 2022, the 2022 Water Revenue bonds with $58,025 principal were issued to fund short-term and long-term capital projects. For additional information, refer to Note 4.
- Retail sales, net of uncollectibles/recovery were $69,854 and $72,452 for the fiscal years ended June 30, 2023 and 2022, respectively. The decrease in sales was primarily due to a decrease in consumption, offset by the rate plan increase.
- Total revenue includes the accounting standard for fair market value adjustment of investments, which will continue to fluctuate based on market valuations. The adjustment was $(536) and $(1,922) in June 30, 2023 and 2022, respectively.
- Operating expense reflects a non-cash pension accounting standard adjustment, which will continue to fluctuate based on yearly actuarial information provided by the California Public Employees' Retirement System (CalPERS). The adjustment was $(471) and $(4,891) in June 30, 2023 and 2022, respectively.

OVERVIEW OF THE FINANCIAL STATEMENTS

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

The Water 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 with additional information about the Water Utility, including historical sales, operating activities, and other relevant data.

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

The ***Statements of Net Position*** present information on all of the Water Utility's assets, liabilities, deferred inflows and outflows of resources and net position. The Statements of Net Position provide information about the nature and amount of the Water Utility's resources and obligations at a specific point in time.

The ***Statements of Revenues, Expenses and Changes in Net Position*** report all of the Water Utility's revenues and expenses for the periods shown.

The ***Statements of Cash Flows*** report the cash provided and used by operating activities, as well as other cash sources, such as investment income and debt financing. They also report other cash uses such as payments for bond principal and capital additions and improvements.

The ***Notes to the Financial Statements*** provide additional information that is essential to a full understanding of the data provided in the Water Utility's financial statements. The Notes to the Financial Statements begin on page 103 of this report.

WATER UTILITY FINANCIAL ANALYSIS

CONDENSED STATEMENTS OF NET POSITION

	2023	2022	2021
Current and other assets	$ 218,580	$ 174,574	$ 92,883
Capital assets	513,341	508,310	499,636
Deferred outflows of resources	16,990	9,647	14,528
Total assets and deferred outflows of resources	748,911	692,531	607,047
Long-term debt outstanding	290,760	239,544	250,728
Other liabilities	44,364	32,469	47,195
Deferred inflows of resources	86,374	98,214	764
Total liabilities and deferred inflows of resources	421,498	370,227	298,687
Net investment in capital assets	295,560	293,641	291,541
Restricted	12,478	10,988	10,599
Unrestricted	19,375	17,675	6,220
Total net position	$ 327,413	$ 322,304	$ 308,360

ASSETS AND DEFERRED OUTFLOWS OF RESOURCES

2023 compared to 2022 The Water Utility’s total assets and deferred outflows of resources were $748,911, reflecting an increase of $56,380 (8.1%) primarily due to the following:

- Current and other assets, comprised of restricted and unrestricted assets, had a net increase of $44,006, primarily due to an increase of $52,198 in restricted cash and cash equivalents related to the issuance of the 2022 Water Revenue Bonds Series A. The increase is offset by a decrease of $8,809 in net pension asset as a result of pension accounting standards.
- Capital assets increased by $5,031 as a result of an increase in additions and improvements to the Water distribution infrastructure system to improve service and reliability to Water Utility's customers, offset by an increase in current years depreciation. Additional capital asset information can be found in the “Capital Assets and Debt Administration” section.
- Deferred outflows of resources increased by $7,343, primarily due to an increase of $8,508 in deferred outflows related to pension as a result of pension accounting standards. The increase is offset by a decrease of $812 in the fair market value of derivatives and a decrease of $270 in loss on refunding due to the amortization.

2022 compared to 2021 Total assets and deferred outflows of resources were $692,531, reflecting an increase of $85,484 (14.1%) over prior year.

- Current and other assets, comprised of restricted and unrestricted assets, had a net increase of $81,691, primarily due to an increase of $82,983 in lease receivable related to the implementation of GASB 87, an increase of $8,809 in net pension asset as a result of pension accounting standards, and an increase of $6,129 in unrestricted cash and cash equivalents, primarily due to positive operating result, offset by a decrease of $15,442 in restricted cash and cash equivalents due to the use of bond proceeds for capital projects.
- Capital assets increased by $8,674 as a result of an increase in additions and improvements to the Water distribution infrastructure system to improve service and reliability to Water Utility's customers, offset by an increase in current years depreciation.
- Deferred outflows of resources decreased by $4,881, primarily due to a decrease of $2,630 in the fair market value of derivatives, a decrease of $1,841 in deferred outflows related to pension as a result of pension accounting standards, and a decrease of $266 in loss on refunding due to the amortization.

LIABILITIES AND DEFERRED INFLOWS OF RESOURCES

2023 compared to 2022 The Water Utility's total liabilities and deferred inflows of resources were $421,498, an increase of $51,271 (13.8%) primarily due to the following:

- Long-term debt outstanding increased by $51,216, primarily due to the issuance of the 2022 Water Revenue Bonds Series A. Additional debt information can be found in the "Capital Assets and Debt Administration" section.
- Other liabilities increased by $11,895, primarily due to an increase of $12,854 in net pension liability, an increase of $1,281 in the current portion of long-term obligations, and an increase of $600 in accrued interest payable. The increase is offset by a decrease of $1,269 in derivative instruments due to a decrease in the fair market value of interest rate swaps, and a decrease of $1,093 in unearned revenues. Additional information on note payable can be found in Note 4 of the accompanying financial statements.
- Deferred inflows of resources decreased by $11,840, primarily due to a decrease of $13,627 in pension-related adjustments, which included the changes in assumptions, the differences between expected and actual experience and the change in projected versus actual earnings on pension plan investments as determined by the plan actuary. The decrease is offset by an increase of $1,264 related to GASB 87 lease adjustments.

2022 compared to 2021 Total liabilities and deferred inflows of resources were $370,227, reflecting an increase of $71,540 (24.0%).

- Long-term debt outstanding decreased by $11,184, primarily due to principal payments on revenue bonds, pension obligation bonds, note payable and financed purchases.
- Other liabilities decreased by $14,726, primarily due to a decrease of $12,203 in net pension liability due to the elimination of the CalPERS net pension liability to net pension asset, a decrease of $3,037 in derivative instruments due to a decrease in the fair market value of interest rate swaps, and a decrease of $1,202 in unearned revenues with the City of Corona, offset by an increase of $601 in accrued interest payable, an increase of $568 in the current portion of long-term obligations, and an increase in accounts payable and other accruals of $446.
- Deferred inflows of resources increased by $97,450, primarily due to the implementation of GASB 87, and pension related adjustments, which included the changes in assumptions, the differences between expected and actual experience and the change in projected versus actual earnings on pension plan investments as determined by the plan actuary.

NET POSITION

2023 compared to 2022 The Water Utility's total net position, which represents the difference between the Water Utility's total assets and deferred outflows of resources less total liabilities and deferred inflows of resources, totaled $327,413, an increase of $5,109 (1.6%).

- The largest portion of the Water Utility's total net position, which is its investment in capital assets of $295,560 (90.3%), had an increase of $1,919 from prior year. Investment in capital assets reflects the Water Utility's investment in source of supply, pumping, treatment, and transmission and distribution facilities, less any related outstanding debt used to acquire these assets (net investment in capital assets). Additional capital asset information can be found in the "Capital Assets and Debt Administration" section.
- The restricted portion of net position totaled $12,478 (3.8%), reflecting an increase of $1,490 and representing resources that are subject to external restrictions on how they may be used. The increase was primarily due to an increase in restricted debt service reserve related to the issuance of the 2022 Water Revenue Bonds Series A. Restricted net position is reserved for items such as debt repayment and funds collected for Water Conservation Programs, and other legally restricted assets.
- The unrestricted portion of net position totaled $19,375 (5.9%) an increase of $1,700 from prior year, primarily attributable to positive operating results and an increase in investment income. Unrestricted net position may be used to meet the Water Utility's ongoing operational needs and obligations to customers and creditors.

WATER UTILITY:
MANAGEMENT'S DISCUSSION AND ANALYSIS

2022 compared to 2021 Total net position increased by $13,944 (4.5%), to $322,304.

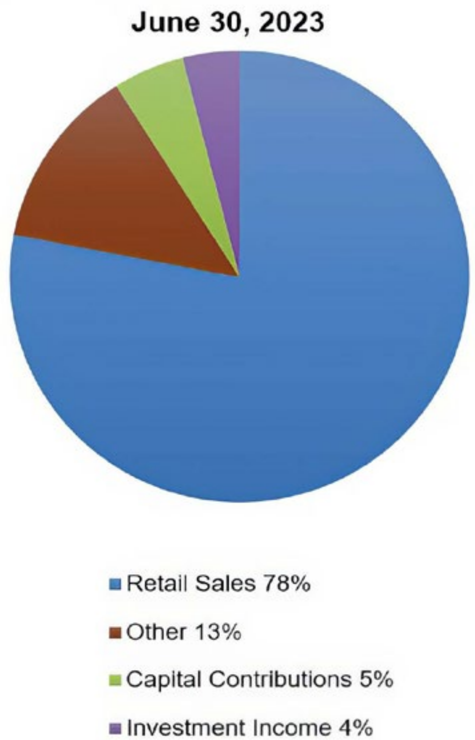
- The largest portion of the Water Utility's total net position, which is its investment in capital assets of $293,641 (91.1%), had an increase of $2,100 from prior year. Investment in capital assets reflects the Water Utility's investment in treatment, pumping, source of supply, transmission and distribution facilities, less any related outstanding debt used to acquire these assets.
- The restricted portion of net position totaled $10,988 (3.4%), reflecting an increase of $389 and representing resources that are subject to external restrictions on how they may be used. The increase was primarily due to an increase in restricted debt service reserve. Restricted net position is reserved for items such as debt repayment and funds collected for Water Conservation Programs, and other legally restricted assets.
- The unrestricted portion of net position totaled $17,675 (5.5%), reflecting an increase of $11,455 from prior year, primarily attributable to positive operating results. Unrestricted net position may be used to meet the Water Utility's ongoing operational needs and obligations to customers and creditors.

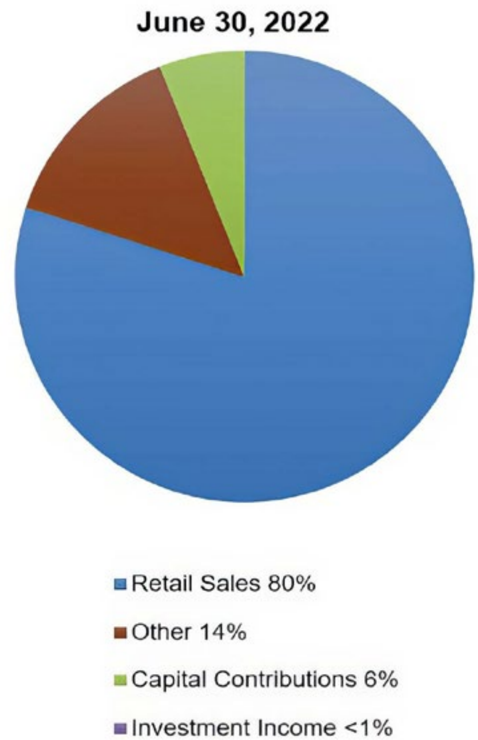
CONDENSED STATEMENTS OF CHANGES IN NET POSITION

	2023	2022	2021
Revenues:			
Retail sales, net	$ 69,854	$ 72,452	$ 70,847
Other revenues	12,109	12,336	12,532
Investment (loss) income	3,613	61	(1)
Capital contributions	4,149	5,693	3,062
Total revenues	89,725	90,542	86,440
Expenses:			
Operations and maintenance	42,738	36,366	39,143
Purchased energy	6,632	6,863	6,523
Depreciation	16,367	16,179	16,346
Amortization	20	11	-
Interest expense and fiscal charges	10,689	9,471	9,731
Total expenses	76,446	68,890	71,743
Transfers:			
Transfers to the City's general fund	(8,170)	(7,708)	(6,972)
Total Transfers	(8,170)	(7,708)	(6,972)
Changes in net position	5,109	13,944	7,725
Net position, July 1	322,304	308,360	300,635
Net position, June 30	$ 327,413	$ 322,304	$ 308,360

WATER UTILITY:
MANAGEMENT'S DISCUSSION AND ANALYSIS

REVENUES BY SOURCES





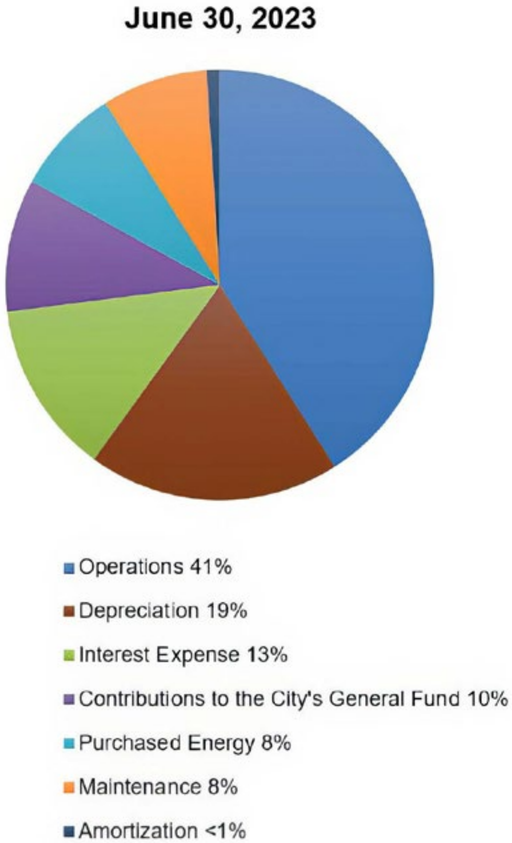
2023 compared to 2022 The Water Utility’s total revenues of $89,725 decreased by $817 (0.9%) primarily due to the following changes:

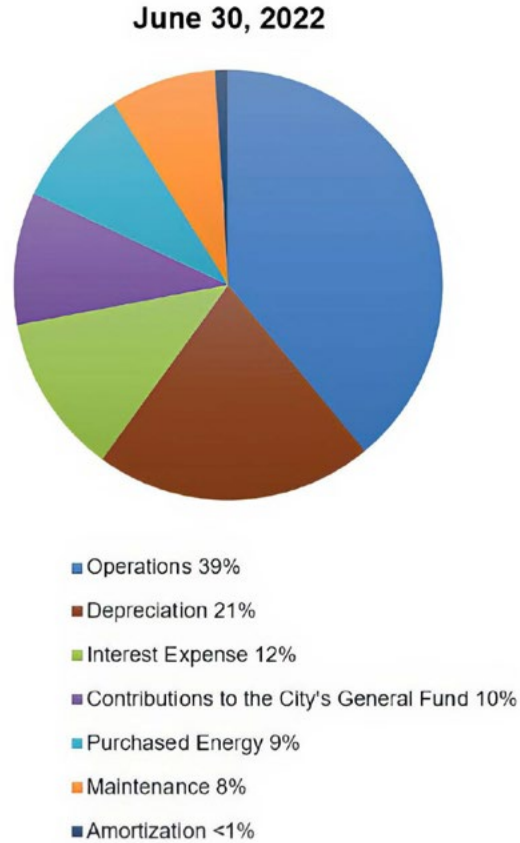
- Retail sales (residential, commercial, industrial, and others), net of uncollectibles/recovery, totaled $69,854, a decrease of $(2,598) (3.6%) from prior fiscal year. Retail sales continue to be the primary revenue source for the Water Utility. The decrease was due to a 13.7% decrease in consumption.
- Other revenues of $12,109 decreased by $227 (1.8%), primarily due to a decrease of of $1,258 related to settlement revenues, offset by an increase of $939 in wholesale water sales compared to prior year.
- Capital contribution of $4,149 decreased by $1,544 (27.1%), primarily due to a decrease of $1,202 in contribution in aid.
- Investment income of $3,613 increased by $3,552 (5,823%), primarily due to a fair market value adjustment of investments and a higher overall interest rate in the current fiscal year.

2022 compared to 2021 The Water Utility’s total revenues of $90,542 increased by $4,102 (4.7%) primarily due to the following changes:

- Retail sales (residential, commercial, industrial, and others), net of uncollectibles/recovery, totaled $72,452, an increase of $1,605 (2.3%) from prior fiscal year. Retail sales continue to be the primary revenue source for the Water Utility. The increase was due to the rate plan increase offset by a 2.1% decrease in consumption.
- Other revenues of $12,336 decreased by $196 (1.6%), primarily due to a decrease of $2,235 in wholesale water sales, offset by an increase of $1,586 related to the SCE Utility billing indifference settlement related to renewable energy self-generation bill and an increase of $608 in water conveyance revenue.
- Capital contribution of $5,693 increased by $2,631 (85.9%), mainly due to the donated assets related to transmission mains, fire hydrants and services.
- Investment income of $61 increased by $62 (100%) due to the leases interest income related to the implementation of GASB 87.

EXPENSES BY SOURCES





2023 compared to 2022 The Water Utility's total expenses, excluding general fund transfer, were $76,446, an increase of $7,556 (11.0%). The increase was primarily due to the following:

- Operations and maintenance expenses of $42,738 increased by $6,372 (17.5%), primarily due to an increase in personnel-related costs resulting from the elimination of the prior year net pension asset and generation of a net pension liability in fiscal year 2022-23, along with increases in administration and general operating expenses.
- Purchased energy and water expenses of $6,632 decreased by $231 (3.4%) from prior year, primarily due to a decrease of $179 in the electricity and chemical costs.

2022 compared to 2021 The Water Utility's total expenses, excluding general fund transfer, were $68,890, a decrease of $2,853 (4.0%). The decrease was primarily due to the following:

- Operations and maintenance expenses of $36,366 decreased by $2,777 (7.1%), mainly due to a non-cash pension adjustment as a result of pension accounting standards.
- Purchased energy and water expenses of $6,863 increased by $340 (5.2%) from prior year, primarily attributable to an increase in the electric and chemical costs.

TRANSFERS

Pursuant to the City's Charter and the voter approval of Measure A on June 4, 2013, the Water Utility may transfer up to 11.5 percent of prior year's gross operating revenues, including adjustments, to the City's general fund. 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. The Water Utility transferred $8,170 and $7,708 for 2023 and 2022, respectively, based on the gross operating revenue provisions in the City's Charter. For additional information, refer to Note 10.

CAPITAL ASSETS AND DEBT ADMINISTRATION

CAPITAL ASSETS

The Water Utility's investment in capital assets includes investments in source of supply, pumping, treatment, transmission and distribution facilities, land, intangibles, construction in progress, and lease and subscription assets as well as general items such as office equipment, furniture, etc.

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

	2023	2022	2021
Utility plant			
Source of supply	$ 54,223	$ 55,231	$ 54,424
Pumping	19,304	19,445	20,146
Treatment	25,652	25,868	27,122
Transmission and distribution	335,719	333,483	332,467
General	4,636	4,514	3,032
Land	20,841	20,841	20,841
Intangibles	10,883	11,005	11,469
Construction in progress	42,055	37,907	30,135
Total utility plant	513,313	508,294	499,636
Lease and subscription assets			
Machinery and equipment	11	16	-
Subscription-based information technology arrangements	17	-	-
Total capital assets	$ 513,341	$ 508,310	$ 499,636

2023 compared to 2022 The Water Utility's investment in capital assets, net of accumulated depreciation, was $513,341, an increase of $5,031 (0.99%) from prior year. The increase resulted primarily from an increase in construction in progress. The Water Utility's significant capital projects include the following:

- $7,919 in distribution pipelines, such as main replacements, distribution system facilities replacement and system expansion.
- $3,323 in well projects, such as potable irrigation well replacements and facility rehabilitation.
- $2,635 in water supply facilities, such as Seven Oaks Dam conservation and recycled water facilities.
- $2,334 in transmission pipelines, such as transmission mains.
- $2,056 in distribution facilities, such as pump station replacements and meters.

2022 compared to 2021 The Water Utility's investment in capital assets, net of accumulated depreciation, was $508,310, an increase of $8,674 (1.74%) from prior year. The increase resulted primarily from the increase in construction in progress. Significant capital projects included the following:

- $10,414 in distribution pipelines, such as main replacements, distribution system facilities replacement and system expansion.
- $5,343 in transmission pipelines, such as transmission mains.
- $2,722 in distribution facilities, such as pump station replacements and meters.
- $2,190 in well projects, such as potable irrigation well replacements and facility rehabilitation.

Additional information regarding capital assets can be found in Note 3 of the accompanying financial statements.

DEBT ADMINISTRATION

The following table summarizes outstanding long-term debt as of June 30:

	2023	2022	2021
Revenue bonds	$ 243,300	$ 192,190	$ 198,830
Unamortized bond premium	21,994	17,472	18,476
Pension obligation bonds	19,924	21,287	22,363
Contracts payable	933	933	1,067
Financed purchases	985	1,218	1,445
Note payable	15,100	16,639	18,138
Less: Current portion of outstanding debt	(11,476)	(10,195)	(9,591)
Total	$ 290,760	$ 239,544	$ 250,728

The Water Utility's bond indentures require a minimum debt service coverage ratio, as defined by the bond covenants, of 1.25. The Water Utility's debt service coverage ratio was 1.93, 2.23, and 2.25 at June 30, 2023, 2022, and 2021, respectively. The debt is backed by the revenues of the Water Utility. Debt service coverage ratio decreased at June 30, 2022 due to an increase in debt service requirements. For additional information, see Note 4 of the accompanying financial statements and the Key Historical Operating Data section.

2023 compared to 2022 The Water Utility's long-term debt increased by $51,216 (21.4%) to $290,760 as a result of the issuance of the 2022 Water Revenue Bonds Series A, offset by current year principal payments and amortization of bond premiums.

2022 compared to 2021 The Water Utility's long-term debt decreased by $11,184 (4.5%) to $239,544 as a result of the principal payments and amortization of bond premiums.

Additional information on the Water Utility's long-term debt can be found in Note 4 of the accompanying financial statements.

CREDIT RATINGS

The Water Utility maintains credit ratings of "AA+", "AA+" and "Aa2" from S&P Global Ratings (S&P), Fitch Ratings (Fitch) and Moody's, respectively. These ratings reflect the Water Utility's strong financial performance, advantageous water supply, investments in infrastructure and rate competitiveness, among many other factors.

WATER UTILITY:
MANAGEMENT'S DISCUSSION AND ANALYSIS

REGULATORY, LEGISLATIVE FACTORS, AND RATES

Utilities are faced with ongoing regulatory and legislative mandates enacted at the federal and state level that will have significant impacts on the operations of the Water Utility.

The State of California has experienced unprecedented drought conditions in recent years resulting in severe impacts to California's water supplies and its ability to meet all of the demands for water in the State. The Water Utility is very fortunate as a water provider in California in that the Water Utility owns, operates and maintains its own water supply and is not typically dependent on imported water from outside sources. The Water Utility currently has sufficient water supplies to meet customer needs even during severe drought conditions; however, the aquifers the Water Utility draws from are experiencing historic low levels. The Water Utility has responded by continuing to offer a wide variety of water conservation programs for its customers in an effort to conserve its water resources.

The Water Utility continues to offer customers a wide variety of water conservation programs that help reduce their water usage and utility costs, and help the City meet State mandates and be more sustainable. These programs provide rebates for residents and businesses to help them save money by conserving water. In an effort to streamline and automate the rebate process, the City formed a partnership with Metropolitan Water District of Southern California to administer and process rebates for high-efficiency toilets, clothes washers, irrigation controllers and many other water-saving devices.

To further provide comprehensive resources and guidance as to how to implement water efficiency practices at residences and businesses, the Water Utility, in partnership with the City created the Street Park Turf Conversion and Demonstration Garden at the Janet Goeske Center. The Demonstration Garden allows residents and businesses to interact with water conservation materials and techniques that conserve water, elevate customer awareness, increase incentive program participation, provide educational opportunities and demonstrate water conservation best practices.

The Water Utility's long-range water supply planning includes significant contributions of both conservation and recycled water. The behavioral changes instituted through conservation and water use efficiency should have some permanent impact. Changes in landscape patterns and uses will have permanent and on-going impacts to water use. Continuing conservation measures could negatively impact the Water Utility revenues and has been addressed in the recent cost of service analysis conducted by the Water Utility.

During fiscal year 2022/23, RPU's water use efficiency programs have supported residents and business to save in excess of 21.8 million gallons of water. These savings are the result of the range of RPU's incentivization programs, which include high-efficiency clothes washers, toilets and weather-based irrigation controllers and the Smart Irrigation Program (SIP).

WATER CONSERVATION

On November 10, 2009, the Governor signed SBX7-7, which focused on reducing urban (municipal) water use, mainly through reductions in residential potable water use, throughout California. The Water Utility's 2015 Urban Water Management Plan (UWMP) reported its Baseline Water Use and calculated its 2020 Urban Water Use Target. In its 2020 UWMP, the Water Utility demonstrated its compliance with SB X7-7 by showing actual 2020 water use below its 2020 Urban Water Use Target.

On May 31, 2018, Governor Jerry Brown signed long-term water-use efficiency bills Senate Bill 606 and Assembly Bill 1668 into law to establish a long-term foundation for water use efficiency and drought planning.

Under AB 1668, the City must set, meet and report water use objectives for its service area using a water budget-based approach by 2025. In total, four water use standards including indoor residential use, outdoor residential use, commercial, industrial, and institutional dedicated irrigation meter use, and water loss will be aggregated to calculate a water purveyor's unique efficient water use target. Final regulations are anticipated to be set in 2024, with reporting beginning 2025. In addition, under SB 606, the City must conduct and submit an Annual Water Supply and Demand Assessment report starting in 2022 and a Drought Risk Assessment every 5 years as part of its Urban Water Management Plan.

WATER UTILITY:
MANAGEMENT'S DISCUSSION AND ANALYSIS

WATER STANDARDS

The development of new and increasingly stringent drinking water regulations by the California Environmental Protection Agency (CalEPA) and the U.S. Environmental Protection Agency (USEPA) are significantly impacting water supply costs throughout the state and the nation. New chemical and biological contaminants are being discovered through more sophisticated research techniques and improved analytical methods. In addition, public health and environmental agencies are now evaluating how anthropogenic factors are impacting our water supplies. Pesticides, pharmaceuticals, and personal care products are being evaluated at trace levels, which can be orders of magnitude lower than what was achievable 20 years ago. As a result, water treatment costs are increasing as federal and state legislators and regulators try to balance public health risk with affordable water supply costs.

On July 21, 2020, the USEPA published a final action to withdraw the Agency's 2011 regulatory determination to regulate perchlorate after finding that perchlorate did not occur with a frequency and at levels of public health concern within the meaning of the Safe Drinking Water Act, and that development of a regulation did not present a meaningful opportunity for health risk reduction for persons served by public water systems. However, the State of California began regulating perchlorate in 2007 with a MCL set at 6 parts per billion ("ppb") and a detection level for purposes of reporting (DLR) of 4 ppb. Beginning July 1, 2021, the DLR was lowered to 2 ppb and will be lowered to 1 ppb effective January 1, 2024. After data is collected at these lower DLR's evaluation of the perchlorate MCL, and possible need for reduction, will occur. A reduction in the perchlorate standard could impact the Water Utility's water supply costs.

In December 2016, the USEPA completed its third review of existing National Primary Drinking Water Regulations (NPDWR) (i.e., the Six-Year Review 3). The USEPA determined that 68 of the 76 NPDWR remain appropriate (i.e., do not need to be revised) and that eight NPDWRs are candidates for regulatory revision. These eight NPDWRs are included in the Stage 1 and the Stage 2 Disinfectants and Disinfection Byproducts Rules, the Surface Water Treatment Rule, the Interim Enhanced Surface Water Treatment Rule and the Long Term 1 Enhanced Surface Water Treatment Rule. The eight NPDWRs are chlorite, Cryptosporidium, Giardia lamblia, haloacetic acids (HAA5), heterotrophic bacteria, Legionella, total trihalomethanes (TTHM) and viruses. Any revision resulting in the lower of these standards may impact the Water Utility's water supply costs. In June 2020, the USEPA began collecting contaminant occurrence data and treatment technique information for its fourth, six-year review which is anticipated to be completed in 2023.

On December 14, 2017, the State Water Resources Control Board (SWRCB) adopted an MCL for 1,2,3-Trichloropropane ("1,2,3-TCP) of 0.000005 mg/L or 5 parts per trillion (ppt). Water Quality Monitoring was initiated in 2018. To date, seven of the City's potable wells show detections of 1,2,3-TCP that exceed the MCL. These wells extract water from the same aquifers that are contaminated by other known anthropogenic chemicals and are currently being treated by existing GAC treatment facilities.

Perfluorooctanoic acid (PFOA) and perfluorooctane sulfonic acid (PFOS) are fluorinated organic chemicals which are part of a family of compounds referred to as per- and polyfluoroalkyl substances (PFAS). PFAS are synthetic compounds that are water and lipid resistant and are useful for a variety of manufacturing processes and industrial applications. In May 2016, the USEPA issued a lifetime health advisory for PFOA and PFOS in drinking water of a combined level of 70 ppt. In February 2021, the USEPA determined to move forward with the process of implementing a national primary drinking water regulation for PFOA and PFOS. In March 2023, the USEPA issued health-based, non-enforceable Maximum Contaminant Level Goals and draft MCLs for six PFAS chemicals: PFOA, PFOS, Perfluorohexane sulfonic acid (PFHxS), Perfluorononanoic acid (PFNA), GenX chemicals, and Perfluorobutane sulfonic acid (PFBS). The proposed MCLs follow: PFOA at 4 ppt, PFOS at 4 ppt, and PFNA, PFHxS, PFBS and GenX regulated together as a Hazard index where the ratio of the chemicals when added together must be less than 1. The Hazard index established Health Based Water Concentrations for PFHxS of 9ppt, PFNA at 10ppt, GenX at 10ppt, and PFBS at 2,000ppt. The proposed PFAS NPDWR is anticipated to be promulgated at the end of 2023 and become effective by the end of 2026. In addition, the USEPA proposed designating PFOA and PFOS as hazardous substances under CERCLA which would increase transparency and hold polluters accountable however, could also increase disposal costs for spent GAC or IX media used to remove PFAS.

With respect to California, in August 2019, the SWRCB-DDW established Notification Levels for PFOA and PFOS of 5.1 and 6.5 ppt, respectively, and in February 2020, DDW issued updated drinking water response levels of 10 ppt for PFOA and 40 ppt for PFOS based on a running four-quarter average. On February 6, 2020 the SWRCB tasked OEHHA to set advisory limits for perfluorohexane sulfonic acid (PFHxS), perfluorobutane sulfonic acid (PFBS), perfluorohexanoic acid (PFHxA), perfluoroheptanoic acid (PFHpA), perfluorononanoic acid (PFNA), perfluorodecanoic acid (PFDA), and 4,8-dioxia-3H-perfluorononanoic acid (ADONA), in addition to PFOS and PFOA. On March 5, 2020 PFBS was issued a notification level of 500 ppt and a response level of 5000 ppt, by the SWRCB. In June 2021, the Office of Environmental Health Hazard Assessment (OEHHA) released a draft PHG for PFOA and PFOS at 0.007 ppt and 1 ppt respectively. Following OEHHA's March 2022 recommendations on PFHxS, the SWRCB-DDW issued a Notification Level of 3 ppt and a Response Level of 20 ppt in October of 2023.

The City believes that PFAS have been in the groundwater basins from which the City draws water in very low concentrations for many years. Recent technological advances enabled water agencies to detect PFAS compounds at such low concentrations. The City's goal is to remain below the Notification Levels, which are lower than the Response Level. Many of the City's wells with detections of PFAS also extract water from the same aquifers that are contaminated by other known anthropogenic chemicals and are currently being treated by existing treatment facilities. Beginning fall 2019, the Board approved the expenditure of approximately $850,000 to test new treatment technologies, assess the feasibility of resurrecting an abandoned treatment plant to treat a well field with high levels of PFAS and develop a long-term water treatment strategy. The Board's review and approval of contracts within the original approved project is ongoing.

The Water Utility will continue to monitor the progress of the proposed standard changes and will advocate for standards that protect human health and are based on the best available science.

CLEAN WATER ACT

In April 2020, the US EPA and US Army published the Navigable Waters Protection Rule to define "Waters of the United Sates." The published rule streamlined the definition so that it includes four simple categories of jurisdictional waters, provides clear exclusions for many water features that traditionally have not been regulated, and defines terms in the regulatory text that have never been defined before. This definition was different from that of the 2015 Clean Water Rule which would have expanded the scope of Federal jurisdiction. However, in June 2021, the USEPA and Department of the Army announced their intent to initiate a new rulemaking process that restores the protections in place prior to the 2015 rule and develops a new rule to establish a durable definition of "Waters of the US" that reflects consideration of prior Supreme Court decisions. This rulemaking process follows a review conducted by the agencies as directed by the January 20, 2021 Executive Order 13990 on "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis." The public comment period closed in February 2022.

FIVE-YEAR WATER RATE PLAN

On May 22, 2018, the City Council approved a five-year Water Rate Plan, the final annual rate increase of 6.5% was effective July 1, 2022 and was in effect through June 30, 2023.

On September 19, 2023, the City Council approved a new five-year Water Rate Plan, which includes system average annual rate increases. The first annual rate increase is effective October 1, 2023 with the following four years effective on July 1 of each year. The approved five-year Water Rate Plan includes annual reviews of the adopted rates by City Council. The system average rate increases are 6.5% each year of the five-year Water Rate Plan. The Water Rate Plan was designed to provide financial stability and correct the imbalance of costs versus revenue recovery.

REQUESTS FOR INFORMATION

This financial report is designed to provide a general overview of the Water 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 – Business Systems and Customer Service, Riverside Public Utilities, 3750 University Avenue, 5th floor, Riverside, CA 92501. Additional financial information can also be obtained by visiting www.RiversidePublicUtilities.com.

WATER UTILITY:
FINANCIAL STATEMENTS

STATEMENTS OF NET POSITION

ASSETS AND DEFERRED OUTFLOWS OF RESOURCES	June 30, 2023 (in thousands)	June 30, 2022
NON-CURRENT ASSETS:		
Capital assets:		
Utility plant, net of accumulated depreciation (Note 3)	$ 513,313	$ 508,294
Lease and subscription assets, net of amortization (Note 3 & 11)	28	16
Total capital assets	513,341	508,310
Restricted assets:		
Cash and cash equivalents at fiscal agent (Note 2)	55,488	4,666
Total non-current restricted assets	55,488	4,666
Other non-current assets:		
Regulatory assets	1,404	880
Leases receivable (Note 11)	84,385	82,983
Net pension asset (Note 6)	-	8,809
Other long-term assets	2,625	2,925
Total other non-current assets	88,414	95,597
Total non-current assets:	657,243	608,573
CURRENT ASSETS:		
Unrestricted assets:		
Cash and cash equivalents (Note 2)	49,191	49,076
Accounts receivable, less allowance for doubtful accounts 2023 $930; 2022 $917	11,019	13,004
Accrued interest receivable	343	248
Leases receivable (Note 11)	1,001	425
Prepaid expenses	212	199
Other current assets	300	300
Total unrestricted current assets	62,066	63,252
Restricted assets:		
Cash and cash equivalents (Note 2)	8,933	7,557
Water Conservation Programs - cash and cash equivalents (Note 2)	3,545	3,330
Water Conservation Programs receivable	134	172
Total restricted current assets	12,612	11,059
Total current assets	74,678	74,311
Total assets	731,921	682,884
DEFERRED OUTFLOWS OF RESOURCES:		
Deferred outflows related to pension (Note 6)	11,588	3,080
Deferred outflows related to other postemployment benefits (Note 7)	644	727
Changes in derivative values	-	812
Loss on refunding	4,758	5,028
Total deferred outflows of resources	16,990	9,647
Total assets and deferred outflows of resources	$ 748,911	$ 692,531

See accompanying notes to the financial statements

WATER ENERGY LIFE
CITY OF RIVERSIDE
PUBLIC UTILITIES

WATER UTILITY:
FINANCIAL STATEMENTS

STATEMENTS OF NET POSITION

NET POSITION, LIABILITIES AND DEFERRED INFLOWS OF RESOURCES	June 30, 2023 (in thousands)	June 30, 2022
NET POSITION:		
Net investment in capital assets	$ 295,560	$ 293,641
Restricted for:		
Debt service (Note 8)	8,933	7,557
Water Conservation Programs	3,545	3,431
Unrestricted	19,375	17,675
Total net position	327,413	322,304
LONG-TERM OBLIGATIONS, LESS CURRENT PORTION (Note 4)	290,760	239,544
OTHER NON-CURRENT LIABILITIES:		
Compensated absences (Note 5)	527	668
Net pension liability (Note 6)	12,854	-
Other postemployment benefits liability (Note 7)	3,872	4,125
Derivative instruments (Note 4)	1,377	2,646
Regulatory liability	4,357	4,096
Lease liability (Note 11)	7	11
SBITA liability (Note 11)	2	-
Total other non-current liabilities	22,996	11,546
CURRENT LIABILITIES PAYABLE FROM RESTRICTED ASSETS:		
Accrued interest payable	2,609	2,009
Water Conservation Programs payable	135	71
Current portion of long-term obligations (Note 4)	9,827	8,510
Total current liabilities payable from restricted assets	12,571	10,590
CURRENT LIABILITIES:		
Accounts payable and other accruals	3,913	4,410
Compensated absences (Note 5)	1,958	1,905
Customer deposits	1,034	1,022
Unearned revenue	52	1,145
Other postemployment benefits liability	171	161
Current portion of long-term obligations (Note 4)	1,649	1,685
Lease liability (Note 11)	5	5
SBITA liability (Note 11)	15	-
Total current liabilities	8,797	10,333
Total liabilities	335,124	272,013
DEFERRED INFLOWS OF RESOURCES:		
Deferred inflows related to pension (Note 6)	1,187	14,814
Deferred inflows related to other postemployment benefits (Note 7)	889	562
Changes in derivative values	196	-
Lease related items (Note 11)	84,102	82,838
Total deferred inflows of resources	86,374	98,214
Total net position, liabilities and deferred inflows of resources	$ 748,911	$ 692,531

See accompanying notes to the financial statements

WATER UTILITY:
FINANCIAL STATEMENTS

STATEMENTS OF REVENUES, EXPENSES AND CHANGES IN NET POSITION

	For the Fiscal Years Ended June 30, 2023 (in thousands)	2022
OPERATING REVENUES:		
Residential sales	$ 44,185	$ 45,784
Commercial sales	23,430	24,635
Other sales	2,268	2,446
Water conveyance revenue	3,381	3,572
Water Conservation Programs	1,090	1,000
Other operating revenue	4,349	3,098
Total operating revenues before uncollectibles	78,703	80,535
Estimated uncollectibles, net of bad debt recovery	(29)	(413)
Total operating revenues, net of uncollectibles	78,674	80,122
OPERATING EXPENSES:		
Operations	34,956	29,391
Maintenance	6,805	6,242
Purchased energy	6,632	6,863
Water conservation	977	733
Depreciation	16,367	16,179
Amortization	20	11
Total operating expenses	65,757	59,419
Operating income	12,917	20,703
NON-OPERATING REVENUES (EXPENSES):		
Investment (loss) income	3,613	61
Interest expense and fiscal charges	(10,689)	(9,471)
Gain on sale of assets	119	709
Other	3,170	3,957
Total non-operating revenues (expenses)	(3,787)	(4,744)
Income (loss) before capital contributions and transfers	9,130	15,959
Capital contributions	4,149	5,693
Transfers out - contributions to the City's general fund	(8,170)	(7,708)
Total capital contributions and transfers	(4,021)	(2,015)
Change in net position	5,109	13,944
NET POSITION, BEGINNING OF YEAR	322,304	308,360
NET POSITION, END OF YEAR	$ 327,413	$ 322,304

See accompanying notes to the financial statements

WATER UTILITY:
FINANCIAL STATEMENTS

STATEMENT OF CASH FLOWS

	For the Fiscal Years Ended June 30, 2023	2022
	(in thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Cash received from customers and users	$ 79,617	$ 80,337
Cash paid to suppliers for goods and services	(31,432)	(32,039)
Cash paid to employees for services	(18,778)	(15,499)
Net cash provided (used) by operating activities	29,407	32,799
CASH FLOWS FROM NON-CAPITAL FINANCING ACTIVITIES:		
Transfers out - contributions to the City's general fund	(8,170)	(7,708)
Debt service payment on pension obligation bonds	(1,363)	(1,075)
Other non-operating receipts	484	1,496
Net cash provided (used) by non-capital financing activities	(9,049)	(7,287)
CASH FLOWS FROM CAPITAL AND RELATED FINANCING ACTIVITIES:		
Purchase of utility plant	(20,181)	(22,738)
Proceeds from the sale of utility plant	130	713
Proceeds from revenue bonds, including premium	63,596	-
Bond issuance costs	(582)	-
Principal paid on long-term obligations	(7,148)	(6,867)
Interest paid on long-term obligations	(10,074)	(9,004)
Capital contributions	2,932	3,590
Lease and subscription payments	(20)	(5)
Net cash provided (used) by capital and related financing activities	28,653	(34,311)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Income (loss) from investments	3,517	(101)
Net increase (decrease) in cash and cash equivalents	52,528	(8,900)
Cash and cash equivalents, beginning of year (including $15,553 and $30,582 at June 30, 2022 and June 30, 2021, respectively, reported in restricted accounts)	64,629	73,529
Cash and cash equivalents, end of year (including $67,966 and $15,553 at June 30, 2023 and June 30, 2022, respectively, reported in restricted accounts)	$ 117,157	$ 64,629

See accompanying notes to the financial statements

STATEMENT OF CASH FLOWS

	For the Fiscal Years Ended June 30, 2023	2022
	(in thousands)	
RECONCILIATION OF OPERATING INCOME TO NET CASH PROVIDED (USED) BY OPERATING ACTIVITIES		
Operating income (loss)	12,917	20,703
ADJUSTMENTS TO RECONCILE OPERATING INCOME (LOSS) TO NET CASH PROVIDED (USED) BY OPERATING ACTIVITIES:		
Depreciation	16,367	16,179
Amortization	20	11
(Increase) decrease in accounts receivable	(146)	(227)
(Increase) decrease in utility billed receivable	1,782	(242)
(Increase) decrease in utility unbilled receivable	243	39
(Increase) decrease in intergovernmental receivable	106	1,846
(Increase) decrease in Water Conservation Programs receivable	38	(20)
(Increase) decrease in prepaid items	(13)	39
Increase (decrease) in accounts payable	(928)	26
Increase (decrease) in accrued payroll	28	180
Increase (decrease) in retainage payable	403	240
Increase (decrease) in compensated absences	(88)	(146)
Increase (decrease) in unearned revenue	(1,093)	(1,202)
Increase (decrease) in Water Conservation Programs payable	64	43
Increase (decrease) in deposits payable	12	9
Changes in net pension liability (asset) and related deferred inflows (outflows) of resources	(472)	(4,890)
Changes in OPEB liability and related deferred outflows and inflows of resources	167	211
Net cash provided (used) by operating activities	$ 29,407	$ 32,799
SCHEDULE OF NON-CASH INVESTING, CAPITAL AND FINANCING ACTIVITIES:		
Capital contributions - capital assets	1,218	2,103
Reduction of note payable including interest, offset by rent credit	1,974	1,890

See accompanying notes to the financial statements

WATER UTILITY:
NOTES TO THE FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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

BASIS OF ACCOUNTING

The Water 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 Water Utility are also in conformity with the Uniform System of Accounts prescribed by the California Public Utilities Commission. The Water Utility is not subject to the regulations of the California Public Utilities Commission.

The Water Utility distinguishes operating revenues and expenses from non-operating items. Operating revenues and expenses generally result from providing services and producing and delivering goods in connection with an enterprise fund's principal ongoing operations. The principal operating revenues of the Water Utility are charges to customers for water sales and services. Operating expenses for the Water Utility include the cost of water sales and services, administrative expenses, and depreciation on capital assets. All revenues and expenses not meeting this definition are reported as non-operating revenues and expenses.

IMPLEMENTATION OF NEW ACCOUNTING PRONOUNCEMENTS

The following new Governmental Accounting Standards Board (GASB) pronouncements were effective and have been implemented for fiscal year 2022-2023 audit:

GASB Statement No. 91, *Conduit Debt Obligations* - This Statement clarifies the existing definition of a conduit debt obligation; establishes that a conduit debt obligation is not a liability of the issuer; establishes standards for accounting and financial reporting of additional commitments and voluntary commitments extended by issuers and arrangements associated with conduit debt obligations; and improves required note disclosures.

GASB Statement No. 94, Public-Private and Public-Public Partnerships and Availability Payment Arrangement - A Public-Private and Public-Public Partnerships (PPP) is an arrangement in which a government (the transferor) contracts with an operator (a governmental or nongovernmental entity) to provide public services by conveying control of the right to operate or use a nonfinancial asset, such as infrastructure or other capital asset (the underlying PPP asset), for a period of time in an exchange or exchange-like transaction. Some PPPs meet the definition of a service concession arrangement (SCA) in which (1) the operator collects and is compensated by fees from third parties; (2) the transferor determines or has the ability to modify or approve which services the operator is required to provide, to whom the operator is required to provide the services, and the prices or rates that can be charged for the services; and (3) the transferor is entitled to significant residual interest in the service utility of the underlying PPP asset at the end of the arrangement. This Statement also provides guidance for accounting and financial reporting for availability payment arrangements (APAs). An APA is an arrangement in which a government compensates an operator for services that may include designing, constructing, financing, maintaining, or operating an underlying nonfinancial asset for a period of time in an exchange or exchange-like transaction.

GASB Statement No. 96, *Subscription-Based Information Technology Arrangements* (SBITA) – This Statement defines Subscription-Based Information Technology Arrangements (SBITA) as a contract that conveys control of the right to use another party's (a SBITA vendor's) information technology (IT) software, alone or in combination with tangible capital assets (the underlying IT assets), as specified in the contract for a period of time in an exchange or exchange-like transaction. This Statement establishes that a SBITA results in a subscription asset—an intangible asset—and a corresponding subscription liability; (3) provides the capitalization criteria for outlays other than subscription payments, including implementation costs of a SBITA; and (4) requires note disclosures regarding a SBITA. The standards for SBITAs are based on the standards established in Statement No. 87, *Leases*, as amended.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

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. Accordingly, actual results could differ from those estimates.

REVENUE RECOGNITION

The Water Utility customers are billed monthly. Unbilled water service charges, including the Water Conservation Programs, are recorded at year-end and are included in accounts receivable. Unbilled accounts receivable totaled $3,456 at June 30, 2023, and $3,703 at June 30, 2022.

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.

WATER UTILITY PLANT AND DEPRECIATION

The Water Utility defines capital assets as assets with an initial, individual cost of more than five thousand dollars and an estimated useful life in excess of one year. Utility plant assets are valued at historical costs or estimated historical cost, if actual historical cost is not available. Costs include labor; materials; 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 recorded over the estimated useful lives of the related assets using the straight-line method. The estimated useful lives are as follows:

Supply, pumping and treatment plant	20-50 years
Transmission and distribution plant	25-50 years
General plant and equipment	5-50 years
Intangibles	5-15 years

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 Statements of Net Position because their use is limited by applicable bond covenants. Proceeds from financed purchase agreements yet to be used for the acquisition of capital equipment are also classified as restricted assets because their use is legally restricted for a specific purpose. Generally, the Water Utility will first apply restricted resources when expenses incurred for which both restricted and unrestricted resources are available.

In June 2004, the Water Utility began collecting a surcharge for Water Conservation Programs. This surcharge was approved by the City Council and was phased in over a three-year period with a 0.5 percent, 1.0 percent and 1.5 percent surcharge effective June 1, 2004, 2005 and 2006, respectively, to be in effect for services rendered on or after June 1, 2004 through May 31, 2014. On April 22, 2014, the City Council approved continuation of the 1.5 percent surcharge effective for the next ten years. The programs and services offered include conservation, education, and water use efficiency programs; and research, development and demonstration programs to advance science and technology with respect to water conservation. The activity associated with the surcharge is reflected in the accompanying financial statements on the Statements of Net Position, Statements of Revenues, Expenses and Changes in Net Position, and Statements of Cash Flows.

CASH AND 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 held at fiscal agent. 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.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

CASH AND INVESTMENTS

In accordance with the Water Utility policy, the Water 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. Cash accounts of all funds are pooled for investment purposes to enhance safety and liquidity, while maximizing interest earnings. The Water 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 Water Utility values its cash and investments in accordance with provisions of GASB Statement No. 72, *Fair Value Measurement and Application*, which requires governmental entities to use valuation techniques that are appropriate under the circumstances and for which sufficient data are available to measure fair value. The techniques should be consistent with one or more of the following approaches: the market approach, the cost approach or the income approach. Valuation includes a hierarchy of inputs with three distinct levels. Level 1 are quoted prices in an active market for identical assets; Level 2 inputs are significant other observable inputs; and Level 3 inputs are significant unobservable inputs. The Water Utility does not value any of its investments using level 3 inputs.

City-wide information concerning cash and investments as of June 30, 2023, including authorized investments, fair value measurement and application, custodial credit risk, credit and interest rate risk for debt securities and concentration of investments, carrying amount and market value of deposits and investments can be found in the notes to the City's financial statements in the City's Annual Comprehensive Financial Report.

DESIGNATED CASH RESERVES

The Riverside Public Utilities Cash Reserve Policy establishes several designated cash reserves in the Water Utility for strategic purposes. Designated reserves are set aside for specific purposes determined by the Board of Public Utilities and City Council. Designated reserves may be held for capital or operating purposes.

Designated cash reserve balances as of June 30, 2023 and 2022 were as follows: Property Reserve $5,926 and $5,804, Recycled Water Reserve $1,013 and $1,158, Customer Deposits $803 and $832, and Capital Repair and Replacement Reserve $2,378 and $2,363, respectively. The combined total for these reserves was $10,120 and $10,157 at June 30, 2023 and 2022, respectively, and is included as a component of unrestricted cash and cash equivalents in the accompanying Statements of Net Position.

DERIVATIVES

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

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

BOND PREMIUMS/DISCOUNTS AND GAINS/LOSSES ON REFUNDING

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

CUSTOMER DEPOSITS

The City holds customer deposits as security for the payment of utility bills and plan check fee deposits for future water connection. The Water Utility's portion of these deposits as of June 30, 2023 and 2022 was $1,034 and $1,022, respectively.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

COMPENSATED ABSENCES

The accompanying financial statements include accruals for salaries, fringe benefits and compensated absences due to employees at June 30, 2023 and 2022. The Water Utility treats compensated absences due to employees as an expense and a liability of which a current portion is included in accounts payable and other accruals in the accompanying Statements of Net Position. The amount accrued for compensated absences was $2,485 at June 30, 2023, and $2,573 at June 30, 2022.

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

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

INSURANCE PROGRAMS

The Water Utility participates in a self-insurance program for workers' compensation and general liability coverage that is administered by the City. The Water 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 shared limit of $1 billion.

City-wide information concerning risks, insurance policy limits and deductibles and designation of general fund balance for risks for the year ended June 30, 2023, may be found in the notes to the City's financial statements in the City's Annual Comprehensive Financial Report.

Although the ultimate amount of losses incurred through June 30, 2023 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 Water Utility were $786 and $975 for the years ended June 30, 2023 and 2022, respectively. Any losses above the City's reserves would be covered through increased rates charged to the Water Utility in future years.

EMPLOYEE RETIREMENT PLAN

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

For purposes of measuring the net pension asset/liability and deferred outflows/inflows of resources related to pensions, and pension expense, information about the fiduciary net position of the City of Riverside California Public Employees' Retirement System plans (Plans) and additions to/deductions from the Plans' fiduciary net position have been determined on the same basis as they are reported by CalPERS. For this purpose, benefit payments (including refunds of employee contributions) are recognized when due and payable in accordance with the benefit terms. Investments are reported at fair value. Further details of employee retirement plan can be found in Note 6.

OTHER POSTEMPLOYMENT BENEFITS (OPEB)

OPEB refers to the benefits, other than pensions, that the City provides as part of an employee's retirement benefits. The net OPEB obligation is defined as the liability of employers contributing to employees for benefits provided through a defined benefit OPEB plan that is administered through a trust. Further details for OPEB can be found in Note 7.

DEFERRED OUTFLOWS AND DEFERRED INFLOWS OF RESOURCES

When applicable, the Statements of Net Position will report a separate section for deferred outflows of resources. Deferred outflows of resources represent outflows of resources (consumption of net position) that apply to future periods and that, therefore, will not be recognized as an expense or expenditure until that time. Deferred outflows of resources consist of changes in derivative values, loss on refunding, and deferred outflows related to pension and OPEB which include pension contributions subsequent to the measurement date, difference between actual and actuarial determined contribution, changes in assumptions and net differences between projected and actual earnings on pension plan investments.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

DEFERRED OUTFLOWS AND DEFERRED INFLOWS OF RESOURCES (CONTINUED)

Conversely, deferred inflows of resources represent inflows of resources (acquisition of net position) that apply to future periods, therefore, are not recognized as an inflow of resources (revenue) until that time. Deferred inflows of resources consist of changes in derivative values, lease related items, deferred inflows related to pension and OPEB which include changes in assumptions, differences between expected and actual experience, and net differences between projected and actual earnings on pension plan investments.

REGULATORY ASSETS AND DEFERRED REGULATORY CHARGES

In accordance with regulatory accounting criteria set forth in GASB Codification (GASB Statement No. 62), enterprise funds that are used to account for rate-regulated activities are permitted to defer certain expenses and revenues that would otherwise be recognized when incurred, provided that the Water Utility is recovering or expects to recover or refund such amounts in rates charged to its customers. Accordingly, regulatory assets and/or deferred regulatory charges related to debt issuance costs have been recognized in the Statements of Net Position.

NET POSITION

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

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

Restricted – this component represents restricted assets less liabilities and deferred inflows related to those assets. Restricted assets are recorded when there are limitations imposed by creditors (such as through debt covenants), contributors, or laws or regulation of other governments or constraints imposed by law through constitutional provisions or through enabling legislation.

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

CONTRIBUTIONS TO THE CITY'S GENERAL FUND

Pursuant to the City of Riverside Charter and the voter approval of Measure A on June 4, 2013, the Water Utility may transfer up to 11.5 percent of prior year's gross operating revenues, including adjustments, to the City's general fund. In fiscal years ended June 30, 2023 and 2022, $8,170 and $7,708, respectively, was transferred, representing 11.5 percent. Additional information can be found in Note 10 of the accompanying financial statements.

BUDGETS AND BUDGETARY ACCOUNTING

The Water Utility presents, and the City Council adopts, a biennial budget. The proposed budget includes estimated expenses and forecasted revenues. The City Council generally adopts the Water Utility's budget in June biennially via resolution. Per City Council direction, the Water Utility transitioned from an incremental budget methodology to a priority-based budgeting methodology in fiscal year 2022-2023.

LEASES AND SUBSCRIPTION-BASED INFORMATION TECHNOLOGY ARRANGEMENTS

Leases are defined by the general government as the right to use an underlying asset. As lessee, the Water Utility recognizes a lease liability and a lease asset at the beginning of a lease period unless the lease is considered a short-term lease or transfers ownership of the underlying asset. Lease assets are measured based on the net present value of the future lease payments at inception, using the weighted average cost of capital, which approximate the incremental borrowing rate. Re-measurement of a lease liability occurs when there is a change in the lease term and/or other changes that are likely to have a significant impact on the lease liability. The Water Utility calculates the amortization of the discount on the lease liability and report that amount as outflows of resources. Payments are allocated first to accrued interest liability and then to the lease liability. Variable lease payments based on the usage of the underlying assets are not included in the lease liability calculations but are recognized as outflows of resources in the period in which the obligation was incurred. As lessor, the Water Utility recognizes a lease receivable. The lease receivable is measured using the net present value of future lease payments to be received for the lease term and deferred inflow of receivables at the

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

LEASES AND SUBSCRIPTION-BASED INFORMATION TECHNOLOGY ARRANGEMENTS (CONTINUED)

beginning of the lease term. Periodic amortization of the discount on the receivable are reported as interest revenue for that period. Deferred inflows of resources are recognized as inflows on a straight-line basis over the term of the lease. This recognition does not apply to short-term leases, contracts that transfer ownership, leases of assets that are investments, or certain regulated leases. Any initial direct costs are reported as an outflow of resources for that period. Re-measurement of lease receivables occur when there are modifications, including but not limited to changes in the contract price, lease term, and adding or removing an underlying asset to the lease agreements. In the case of a partial or full lease termination, the carrying value of the lease receivable and the related deferred inflow of resources will be reduced and will include a gain or loss for the difference. For lease contracts that are short-term, the Water Utility recognizes short-term lease payments as inflows of resources (revenues) based on the payment provisions of the lease contract. Liabilities are only recognized if payments are received in advance, and receivables are only recognized if payments are received subsequent to the reporting period. Additional disclosures regarding regulated leases are in Note 11.

Subscription-Based Information Technology Arrangements (SBITAs) are contracts that convey control of the right to use another party's IT software, alone or in combination with tangible capital assets, as specified in the contract for a period of time in an exchange or exchange-like transaction. To determine whether a contract conveys control of the right to use the underlying IT assets, the Water Utility assesses both the right to obtain the present service capacity from use of the underlying IT assets and the right to determine the nature and manner of use of the underlying IT assets as specified in the contract. Contracts that solely provide IT support services are excluded from the definition of a SBITA. The subscription term is the period during which the Water Utility has a noncancellable right to use the underlying IT assets, plus the periods covered by the Water Utility's option to extend the SBITA if it is reasonably certain, based on all relevant factors, that the government will exercise that option. Periods for which both the government and the SBITA vendor have an option to terminate the SBITA without permission from the other party (or if both parties have to agree to extend) are cancelable periods and are excluded from the subscription term. Additional disclosures regarding SBITAs are in Note 11.

RECLASSIFICATIONS

Certain reclassifications have been made to prior year's financial statements to conform with the current year's presentation. Such reclassifications have no effect on the net position or the changes in net position.

2. CASH AND INVESTMENTS

Cash and investments at June 30, 2023 and 2022, consist of the following (in thousands):

	June 30, 2023	June 30, 2022
	Fair Value	
Equity interest in City Treasurer's investment pool	$ 61,669	$ 59,963
Cash and cash equivalents at fiscal agent	55,488	4,666
Total cash and investments	$ 117,157	$ 64,629

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

	June 30, 2023	June 30, 2022
Unrestricted cash and cash equivalents	$ 49,191	$ 49,076
Restricted cash and cash equivalents	12,478	10,887
Restricted cash and cash equivalents at fiscal agent	55,488	4,666
Total cash and investments	$ 117,157	$ 64,629

The investment types in the tables below related to the Water Utility’s investments in the City Treasurer’s investment pool represent the Water Utility’s prorated share of the investment types in the investment pool and do not represent ownership interests in the individual investments.

2. CASH AND INVESTMENTS (CONTINUED)

The Water Utility categorizes its fair value measurements within the fair value hierarchy established by generally accepted accounting principles. The Water Utility has the following recurring fair value measurements as of June 30, 2023 and 2022:

Investment Type	June 30, 2023 Fair Value	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Investments not Subject to Fair Value Hierarchy
Held by fiscal agent					
Money market funds	$ 55,488	$ -	$ -	$ -	$ 55,488
City Treasurer's investment pool[1]					
Money market funds	1,116	-	-	-	1,116
Joint powers authority pools	11,896	-	-	-	11,896
Mortgage pass-through securities	2,031	-	2,031	-	-
Asset-backed securities	5,155	-	5,155	-	-
US Treasury obligations	17,853	-	17,853	-	-
Federal agency obligations	8,538	-	8,538	-	-
Medium-term corporate notes	12,849	-	12,849	-	-
Supranational securities	2,231	-	2,231	-	-
Total	$ 117,157	$ -	$ 48,657	$ -	$ 68,500

Investment Type	June 30, 2022 Fair Value	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Investments not Subject to Fair Value Hierarchy
Held by fiscal agent					
Money market funds	$ 4,666	$ -	$ -	$ -	$ 4,666
City Treasurer's investment pool[1]					
Money market funds	1,663	-	-	-	1,663
Joint powers authority pools	9,334	-	-	-	9,334
Local agency investment fund	7,092	-	-	-	7,092
Mortgage pass-through securities	2,345	-	2,345	-	-
Asset backed securities	4,743	-	4,743	-	-
US Treasury obligations	13,540	-	13,540	-	-
Federal agency obligations	8,005	-	8,005	-	-
Medium-term corporate notes	10,519	-	10,519	-	-
Supranational securities	2,441	-	2,441	-	-
Negotiable certificate of deposit	281	-	281	-	-
Total	$ 64,629	$ -	$ 41,874	$ -	$ 22,755

[1]Additional information on investment types, fair value measurement, interest rate risk and credit risk may be found in the notes to the City's financial statements in the City's Annual Comprehensive Financial Report.

2. CASH AND INVESTMENTS (CONTINUED)

Cash and investments distribution by maturities as of June 30, 2023 and 2022, are as follows:

Investment Type	June 30, 2023 Fair Value	Remaining Maturity (in Months) 12 Months or Less	13 to 36 Months	37 to 60 Months
Held by fiscal agent				
Money market funds	$ 55,488	$ 55,488	$ -	$ -
City Treasurer's investment pool[1]				
Money market funds	1,116	1,116	-	-
Joint powers authority pools	11,896	11,896	-	-
Mortgage pass-through securities	2,031	320	737	974
Asset-backed securities	5,155	57	2,299	2,799
US Treasury obligations	17,853	2,938	5,274	9,641
Federal agency obligations	8,538	2,026	5,187	1,325
Medium-term corporate notes	12,849	641	6,992	5,216
Supranational securities	2,231	-	2,231	-
Total	$ 117,157	$ 74,482	$ 22,720	$ 19,955

Investment Type	June 30, 2022 Fair Value	Remaining Maturity (in Months) 12 Months or Less	13 to 36 Months	37 to 60 Months
Held by fiscal agent				
Money market funds	$ 4,666	$ 4,666	$ -	$ -
City Treasurer's investment pool[1]				
Money market funds	1,663	1,663	-	-
Joint powers authority pools	9,334	9,334	-	-
Local agency investment fund	7,092	7,092	-	-
Mortgage pass-through securities	2,345	654	1,365	326
Asset-backed securities	4,743	-	2,544	2,199
US Treasury obligations	13,540	1,628	6,576	5,336
Federal agency securities	8,005	1,248	5,017	1,740
Medium-term corporate notes	10,519	482	4,727	5,310
Supranational securities	2,441	-	848	1,593
Negotiable certificate of deposit	281	281	-	-
Total	$ 64,629	$ 27,048	$ 21,077	$ 16,504

[1]Additional information on investment types, fair value measurement, interest rate risk and credit risk may be found in the notes to the City's financial statements in the City's Annual Comprehensive Financial Report.

2. CASH AND INVESTMENTS (CONTINUED)

Presented below is the actual rating as of June 30, 2023 and 2022 for each investment type:

Investment Type	June 30, 2023 Fair Value	Rating as of Year End AAA	AA	A	Unrated
Held by Fiscal Agent					
Money Market Funds	$ 55,488	$ 55,488	$ -	$ -	$ -
City Treasurer's investment pool[1]					
Money market funds	1,116	1,116	-	-	-
Joint powers authority pools	11,896	-	-	-	11,896
Mortgage pass-through securities	2,031	2,031	-	-	-
Asset-backed securities	5,155	3,898	-	-	1,257
US Treasury obligations	17,853	17,853	-	-	-
Federal agency obligations	8,538	7,229	-	-	1,309
Medium-term corporate notes	12,849	406	4,447	6,273	1,723
Supranational securities	2,231	1,149	-	-	1,082
Total	$ 117,157	$ 89,170	$ 4,447	$ 6,273	$ 17,267

Investment Type	June 30, 2022 Fair Value	Rating as of Year End AAA	AA	A	Unrated
Held by fiscal agent					
Money market funds	$ 4,666	$ -	$ -	$ -	$ 4,666
City Treasurer's investment pool[1]					
Money market funds	1,663	1,297	-	-	366
Joint powers authority pools	9,334	-	-	-	9,334
Local agency investment fund	7,092	-	-	-	7,092
Mortgage pass-through securities	2,345	2,345	-	-	-
Asset backed securities	4,743	3,777	-	-	966
US Treasury obligations	13,540	13,540	-	-	-
Federal agency obligations	8,005	8,005	-	-	-
Medium-term corporate notes	10,519	-	3,733	5,740	1,046
Supranational securities	2,441	1,262	-	-	1,179
Negotiable certificate of deposit	281	-	-	281	-
Total	$ 64,629	$ 30,226	$ 3,733	$ 6,021	$ 24,649

[1]Additional information on investment types, fair value measurement, interest rate risk and credit risk may be found in the notes to the City's financial statements in the City's Annual Comprehensive Financial Report.

3. CAPITAL ASSETS

The following is a summary of changes in utility plant and lease and subscription assets during the fiscal years ended June 30, 2023 and 2022 (in thousands):

	Balance As of 6/30/2021	Additions	Retirements/ Transfers	Balance As of 6/30/2022	Additions	Retirements/ Transfers	Balance As of 6/30/2023
Source of supply	$ 78,102	$ 2,784	$ -	$ 80,886	$ 1,046	$ -	$ 81,932
Pumping	35,162	51	-	35,213	618	(3)	35,828
Treatment	44,768	26	-	44,794	1,066	-	45,860
Transmission and distribution	535,520	12,358	(8,222)	539,656	13,827	(1,365)	552,118
General	16,458	1,970	(153)	18,275	704	(254)	18,725
Intangible	4,171	10	-	4,181	-	-	4,181
Depreciable utility plant	714,181	17,199	(8,375)	723,005	17,261	(1,622)	738,644
Less accumulated depreciation							
Source of supply	(23,678)	(1,977)	-	(25,655)	(2,054)	-	(27,709)
Pumping	(15,016)	(752)	-	(15,768)	(756)	-	(16,524)
Treatment	(17,646)	(1,280)	-	(18,926)	(1,282)	-	(20,208)
Transmission and distribution	(203,053)	(11,338)	8,218	(206,173)	(11,578)	1,352	(216,399)
General	(13,426)	(487)	152	(13,761)	(576)	248	(14,089)
Intangible	(3,677)	(344)	-	(4,021)	(122)	-	(4,143)
Accumulated depreciation	(276,496)	(16,178)	8,370	(284,304)	(16,368)	1,600	(299,072)
Net depreciable utility plant	437,685	1,021	(5)	438,701	893	(22)	439,572
Land	20,841	-	-	20,841	-	-	20,841
Intangible, non-amortizable	10,975	-	(130)	10,845	-	-	10,845
Construction in progress	30,135	22,864	(15,092)	37,907	20,204	(16,056)	42,055
Nondepreciable utility plant	61,951	22,864	(15,222)	69,593	20,204	(16,056)	73,741
Total utility plant, net	$ 499,636	$ 23,885	$ (15,227)	$ 508,294	$ 21,097	$ (16,078)	$ 513,313
Lease and subscription assets, being amortized [1]							
Machinery and equipment-Intangible	-	21	-	21	-	-	21
Subscription-based information technology arrangements	-	-	-	-	32	-	32
Total lease and subscription assets	-	21	-	21	32	-	53
Less lease accumulated amortization							
Machinery and equipment-Intangible	-	(5)	-	(5)	(5)	-	(10)
Subscription-based information technology arrangements	-	-	-	-	(15)	-	(15)
Total lease accumulated amortization	-	(5)	-	(5)	(20)	-	(25)
Total lease and subscription assets, net	-	16	-	16	12	-	28
Total capital assets being depreciated, net	$ 499,636	$ 23,901	$ (15,227)	$ 508,310	$ 21,109	$ (16,078)	$ 513,341

[1]GASB 87 *Leases* was implemented effective July 1, 2021. GASB 96 *Subscription-Based Information Technology Arrangements* (SBITA) was implemented effective July 1, 2022. For additional information, refer to Notes 1 and 11.

4. LONG-TERM OBLIGATIONS

The following is a summary of changes in long-term obligations during the fiscal years ended June 30, 2023 and 2022 (in thousands):

	Balance As of 6/30/2021	Additions	Reductions	Balance As of 6/30/2022	Additions	Reductions	Balance As of 6/30/2023	Due Within One Year
Revenue bonds	$ 217,306	$ -	$ (7,644)	$ 209,662	$ 63,596	$ (7,964)	$ 265,294	$ 7,950
Pension obligation bonds	22,363	-	(1,076)	21,287	-	(1,363)	19,924	1,640
Direct Borrowings:								
Financed purchases	1,445	-	(227)	1,218	-	(233)	985	237
Notes payable	18,138	-	(1,499)	16,639	-	(1,539)	15,100	1,499
Contracts payable - Water stock acquisition rights	1,067	-	(134)	933	-	-	933	150
Total long-term obligations	$ 260,319	$ -	$ (10,580)	$ 249,739	$ 63,596	$ (11,099)	$ 302,236	$ 11,476

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

CONTRACTS PAYABLE

	June 30, 2023	June 30, 2022
Water Stock Acquisitions: Payable to various water companies	$ 933	$ 933
Total contracts payable	933	933

PENSION OBLIGATION BONDS PAYABLE

	June 30, 2023	June 30, 2022
$31,960 2017 Taxable Pension Obligation Bonds Series A: fixed rate bonds issued by the City due in annual installments from $2,910 to $3,580 through June 2027, with coupons from 1.3 to 3.1 percent. The Water Utility's proportional share of the outstanding debt is 10.7 percent.	$ 1,465	$ 1,807
$201,080 2020 Taxable Pension Obligation Bonds Series A (Miscellaneous): fixed rate bonds issued by the City due in annual installments from $1,285 to $14,625 through June 2045, with coupons from 1.6 to 3.9 percent. The Water Utility's proportional share of the outstanding debt is 10.2 percent.	18,459	19,480
Total pension obligation bonds payable	19,924	21,287

REVENUE BONDS PAYABLE

	June 30, 2023	June 30, 2022
$67,790 2009 Water Revenue Series B Bonds: fixed rate, federally taxable, Build America Bonds due in annual principal installments from $2,475 to $4,985 from October 1, 2021 through October 1, 2039, interest from 3.3 to 4.1 percent.	$ 62,760	$ 65,315
$59,000 2011 Water Revenue/Refunding Series A Bonds: variable rate bonds due in annual principal installments from $2,375 to $3,950 through October 1, 2035. Interest rate is subject to daily repricing (net interest rate, including swaps, at June 30, 2019 was 3.2 percent). Partially refunded $26,900 on April 1, 2019 with 2019A Water Refunding Bonds.	24,050	24,050
$114,229 2019 Water Revenue Refunding Series A Bonds: fixed rate bonds due in annual principal installments from $1,680 to $8,455 through October 1, 2048, interest of 5.0 percent.	98,465	102,825
$58,025 2022 Water Revenue Series A Bonds: fixed rate bonds due in annual principal installments from $735 to $3,605 through October 1, 2052, interest of 5.0 percent.	58,025	-
Total water revenue bonds payable	243,300	192,190
Total water revenue bonds, pension obligation bonds and contracts payable	264,157	214,410
Unamortized bond premium	21,994	17,472
Total water revenue bonds, pension obligation bonds and contracts payable, including bond premium	286,151	231,882
Less current portion	(9,740)	(8,428)
Total long-term water revenue bonds, pension obligation bonds and contracts payable	$ 276,411	$ 223,454

4. LONG-TERM OBLIGATIONS (CONTINUED)

The Water Utility is obligated to pay its share of the City's pension obligation bonds, which the City issued in 2005 and refinanced a portion in May 2017. The bond proceeds were deposited with CalPERS to fund the unfunded actuarial accrued liability for non-safety employees.

In fiscal year ended June 30, 2020, the City issued $432,165 2020 Taxable Pension Obligation Bonds Series A. The bonds were issued to reduce the City's unfunded pension liability in both the City's Miscellaneous and Safety CalPERS plans. It is estimated the issuance will save the City's General Fund approximately $178.5 million throughout the life of the bonds. The fixed rate bonds issued by the City due in annual installments from $1,285 to $14,625 through June 2045, with coupons from 1.6 to 3.9 percent. The Water Utility's proportional share of the miscellaneous plan is 10.2 percent.

The Water Utility's proportional share of the outstanding principal amount of both pension obligation bonds was $19,924 and $21,287 as of June 30, 2023 and 2022, respectively. For more discussion relating to the City's pension obligation bond issuance, see the notes to the City's financial statements in the City's Annual Comprehensive Financial Report for the fiscal year ended June 30, 2023.

Remaining pension obligation bond debt service payments will be made from revenues of the Water Fund. Annual debt service requirements to maturity as of June 30, 2023 are as follows (in thousands):

Fiscal Year	Principal	Interest	Total
2024	$ 1,640	$ 642	$ 2,282
2025	1,815	605	2,420
2026	1,867	562	2,429
2027	1,793	514	2,307
2028	1,182	465	1,647
2029-2033	4,282	1,900	6,182
2034-2038	4,823	1,033	5,856
2039-2043	2,522	224	2,746
Total	$ 19,924	$ 5,945	$ 25,869

All water revenue bonds are covenanted per the Amended and Restated Resolution No. 17664 (Water) Master Resolution that upon the occurrence and continuation of an event of default, the owners of 25% in aggregate amount of Bond Obligation may, by written notice to the City, declare the entire unpaid principal and accreted value of the bonds due and payable should the City fail to pay its debts as they become due or upon the entry of any decree or order of bankruptcy of the City.

$58,025 Water Revenue Bonds Series A. The bonds were issued in December 2022 to fund short-term and long-term capital projects. Interest on the bonds is 5%, payable in April and October of each year. Principal payments are due in annual installments through October 1, 2052, and range from $735 to $3,605.

Remaining revenue bond debt service payments will be made from revenues of the Water Fund. Annual debt service requirements to maturity as of June 30, 2023 are as follows (in thousands):

Fiscal Year	Principal	Interest	Total
2024	$ 7,950	$ 11,050	$ 19,000
2025	8,460	10,664	19,124
2026	8,840	10,257	19,097
2027	9,245	9,831	19,076
2028	9,665	9,385	19,050
2029-2033	54,430	39,883	94,313
2034-2038	66,100	27,022	93,122
2039-2043	35,515	13,817	49,332
2044-2048	24,110	7,878	31,988
2049-2053	18,985	2,193	21,178
Premium	21,994	-	21,994
Total	$ 265,294	$ 141,980	$ 407,274

4. LONG-TERM OBLIGATIONS (CONTINUED)

The Water Utility has a number of debt issuances (revenue bonds) outstanding that are collateralized by the pledging of water revenues. The amount and term of the remainder of these commitments are indicated in the revenue bonds payable and annual debt service requirements to maturity tables presented within this Note 4. The purpose of the debt issuances was for the financing of various Water Utility capital improvement projects. For June 30, 2023 and 2022, debt service payments as a percentage of the pledged gross revenue, net of certain expenses where so required by the debt agreement, are indicated in the table below. The debt service coverage ratios also approximate the relationship of the debt service to pledged revenue for the remainder of the term of the commitment.

Fiscal Year Ended	Description of Pledged Revenues	Annual Amount of Pledged Revenue (net of expenses) [1, 2, 3]	Annual Debt Service Payments	Debt Service Coverage Ratio
June 30, 2023	Water revenues	$ 36,362	$ 18,848	1.93
June 30, 2022	Water revenues	$ 37,986	$ 17,069	2.23

[1]Excludes GASB 68 Accounting and Financial Reporting for Pension non-cash adjustments of $(471) and $(4,891) for June 30, 2023 and 2022, respectively.

[2]Excludes GASB 75 Accounting and Financial Reporting for Postemployment Benefits Other Than Pensions non-cash adjustments of $168 and $210 for June 30, 2023 and 2022, respectively.

[3]Includes GASB 87 *Leases* net revenue adjustment of $728 and $708 for June 30, 2023 and 2022, respectively.

LINE OF CREDIT

On February 1, 2019, the City entered into a subordinate line of credit agreement with U.S. Bank, National Association. The agreement was renewed on February 1, 2022. The Subordinate Line of Credit is a tool approved through the Electric and Water Utility Five-Year Rate Plan to manage rate increases by enabling the Water Utility to reduce cash levels while maintaining compliance with the Riverside Public Utilities Cash Reserve Policy. Under the terms and conditions of the agreement, the City may borrow up to $25,000 for purposes of the capital or operating financial needs of the Water System. There were no borrowings against the line as of June 30, 2023.

LETTERS OF CREDIT

The Water Utility's Issue of the 2011A Water Revenue Bonds require an additional layer of security between the Water Utility and the purchaser of the bonds. The Water Utility has entered into the following letters of credit (LOC) in order to provide liquidity should all or a portion of the debt be optionally tendered to the remarketer without being successfully remarketed:

Debt Issue	LOC Provider	LOC Expiration Date	Annual Commitment Fee
2011A Water Revenue Bonds	PNC Bank, NA	2025	0.230 %

To the extent that remarketing proceeds are insufficient or not available, tendered amounts will be paid from drawings made under an irrevocable direct-pay letter of credit.

INTEREST RATE SWAPS ON REVENUE BONDS

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

4. LONG-TERM OBLIGATIONS (CONTINUED)

INTEREST RATE SWAPS ON REVENUE BONDS (CONTINUED)

A summary of the derivative activity for the year ended June 30, 2023 is as follows:

	Notional Amount	Fair Value as of June 30, 2023	Change in Fair Value for Fiscal Year
2011 Water Refunding/Revenue Bonds Series A	$ 24,050	$ (1,377)	$ 1,269

Objective: In order to lower borrowing costs as compared to fixed-rate bonds, the Water Utility entered into an interest rate swap agreement in connection with its $59,000 2011 Water Refunding/Revenue Series A Bonds.

Terms: Per the existing swap agreement, the Water Utility pays the counterparty a fixed payment and receives a variable payment computed as 62.68 percent of the London Interbank Offering Rate ("LIBOR") one-month index plus 12 basis points. The swap has a notional amount equal to the principal amount stated above. The notional value of the swap and principal amount of the associated debt decline by $1,475 to $3,950 until the debt is completely retired in fiscal year 2036.

The bonds and the related swap agreement for the 2011 Water Refunding/Revenue Series A Bonds mature on October 1, 2035. As of June 30, 2023, rates were as follows:

Interest rate swap:	Terms	Rates
Fixed payment to counterparty	Fixed	3.20000 %
Variable payment from counterparty	62.68 LIBOR + 12bps	(0.72101)%
Net interest rate swap payments		2.47899 %
Variable-rate bond coupon payments		0.65145 %
Synthetic interest rate on bonds		3.13044 %

Fair value: As of June 30, 2023, in connection with the swap agreement, the transactions had a total negative fair value of $(1,377). Because the coupons on the Water Utility's variable-rate bonds adjust to changing interest rates, the bonds do not have a corresponding fair value decrease. The fair value was developed by a pricing service using the zero-coupon method. This method calculates the future net settlement payments required by the 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, 2023, the Water Utility was not exposed to credit risk because the swap had a negative fair value. The swap counterparty, J.P. Morgan Chase & Co. was rated A- by Standard & Poor's (S&P). To mitigate the potential for credit risk, the swap agreement requires the fair value of the swap to be collateralized by the counterparty with U.S. Government securities if the counterparty's rating decreases to negotiated trigger points. Collateral would be posted with a third-party custodian. At June 30, 2023, there is no requirement for collateral posting for the outstanding swap.

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

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

4. LONG-TERM OBLIGATIONS (CONTINUED)

INTEREST RATE SWAPS ON REVENUE BONDS (CONTINUED)

Swap payments and associated debt: As of June 30, 2023, 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.

	Variable-Rate Bonds			
Fiscal Year Ending June 30,	Principal	Interest	Interest Rate Swaps, Net	Total
2024	$ -	$ 164	$ 625	$ 789
2025	-	164	625	789
2026	-	164	625	789
2027	-	164	625	789
2028	-	164	625	789
2029-2033	12,575	619	2,357	15,551
2034-2038	11,475	100	379	11,954
Total	$ 24,050	$ 1,539	$ 5,861	$ 31,450

Replacement of London Interbank Offering Rate (LIBOR): As of July 1, 2023, LIBOR is no longer an appropriate benchmark interest rate for a derivative instrument that hedges the interest risk for taxable debt for purposes of GASB Statement 53.

NOTE PAYABLE

Note payable consists of several agreements with Harvest A OSR, LLC, Stockbridge NLP, LLC, and related entities (collectively Hillwood) for their development of logistic centers located in the City of San Bernardino. As a part of these agreements, the Water Utility leases land to Hillwood and also purchased land from Hillwood with a subsequent lease-back to the entity. In addition, the agreements require Hillwood to relocate wells located on the properties as well as terminate an existing lease. In consideration of the cost of the land purchase, well relocations and lease termination, the Water Utility will make payments to Hillwood in the form of a credit with Hillwood's rental payments to the Water Utility for the first 15 years of the leases. These agreements resulted in a total liability to the Water Utility of $15,100, as of June 30, 2023.

Estimated annual rent credits, which are adjusted annually based on Consumer Price Index (CPI), to be applied to the land purchase and well relocation agreements commencing in 2014 with an effective interest rate of 5.19 percent, are as follows (in thousands):

Fiscal Year	Principal	Interest	Total
2024	$ 909	$ 442	$ 1,351
2025	1,028	392	1,420
2026	1,156	335	1,491
2027	1,296	272	1,568
2028	1,447	201	1,648
2029-2030	3,078	157	3,235
Total	$ 8,914	$ 1,799	$ 10,713

4. LONG-TERM OBLIGATIONS (CONTINUED)

Estimated annual rent credits, which are adjusted annually based on CPI, to be applied to the well relocation agreement commencing in 2018 with an effective interest rate of 3.00 percent, are as follows (in thousands):

Fiscal Year	Principal	Interest	Total
2024	$ 290	$ 98	$ 388
2025	300	89	389
2026	309	79	388
2027	319	70	389
2028	329	59	388
2029-2033	1,714	133	1,847
Total	$ 3,261	$ 528	$ 3,789

Annual rent credits to be applied for the lease termination agreement commencing in 2018, are as follows (in thousands):

Fiscal Year Ending	Principal	Interest	Total
2024	$ 300	$ -	$ 300
2025	300	-	300
2026	300	-	300
2027	300	-	300
2028	300	-	300
2029-2033	1,425	-	1,425
Total	$ 2,925	$ -	$ 2,925

FINANCED PURCHASES

In fiscal year ended June 30, 2017, the Water Utility participated in the City's purchase financing program for the acquisition of water system heavy vehicles and equipment. The heavy vehicles and equipment financed purchases are for a ten-year term of annual payments with an interest rate of 2.36 percent. Gross proceeds of $2,305 were received for the financing. The total liability with the current portion included in current portion of long-term obligations as of June 30, 2023 and 2022 was $985 and $1,218, respectively. The annual payments for the life of the agreements are $260 annually through fiscal year ending June 30, 2027. As of June 30, 2023 total outstanding payments are $1,039, with $985 representing principal and $54 representing interest.

5. COMPENSATED ABSENCES

A liability is recorded for unused vacation and similar compensatory leave balances since the employees' entitlement to these balances are attributable to services already rendered and it is probably that virtually all of these balances will be liquidated by either paid time-off or payments upon termination or retirement.

Below is a summary of changes in compensated absences for the Water Utility during the fiscal year.

	Balance As of 6/30/2021	Additions	Reductions	Balance As of 6/30/2022	Additions	Reductions	Balance As of 6/30/2023	Due Within One Year
Compensated absences	$ 2,719	$ 1,868	$ (2,014)	$ 2,573	$ 1,940	$ (2,028)	$ 2,485	$ 1,958

6. EMPLOYEE RETIREMENT PLAN

PLAN DESCRIPTION

The City contributes to CalPERS, an agent multiple employer public employee defined benefit pension plan. CalPERS provides retirement and disability benefits, annual cost-of-living adjustments, and death benefits to plan members and beneficiaries. CalPERS acts as a common investment and administrative agent for participating public entities within the State of California. CalPERS issues a publicly available financial report that includes financial statements and required supplementary information for the cost sharing plans that are administered by CalPERS. Benefit provisions and all other requirements are established by state statute and City ordinance. A copy of CalPERS' annual financial report may be obtained online at www.calpersca.gov. The Water Utility participates in the City's Miscellaneous (non-safety) Plan (the Plan).

FUNDING POLICY

The City has contributed at the actuarially determined rate provided by CalPERS' actuaries. Participants are required to contribute 8% of their annual covered salary. The City has a multiple tier retirement plan with benefits varying by plan. All permanent full-time and selected part-time employees are eligible for participation in CalPERS. Benefits vest after five years of service and are determined by a formula that considers the employee's age, years of service and salary. Under the Plan, the City pays the employees' contribution to CalPERS for employees hired on or before specific dates as follows:

- 1st Tier –
    - The retirement formula is 2.7% at age 55 for employees hired on or before October 18, 2011. Effective January 1, 2018 for unrepresented employees (Sr. Management, Management, Professional, Para-professional, Supervisory, Confidential, and Executive units, excluding the Chief of Police and the Fire Chief), the employees were required to pay 2% of their pensionable income, with the City contributing the other 6%. Effective January 1, 2019, employees were required to pay an additional portion of their pensionable income. This portion is a three-year increase of 2% (2019), 2% (2020) and 2% (2021). As of 2021, employees are contributing the entire 8% of their pensionable income.

    - The retirement formula is 2.7% at age 55 for SEIU and SEIU Refuse employees hired before June 7, 2011. Currently, employees are required to pay 7% of their pensionable income with the City contributing the other 1%. Effective January 1, 2019, employees were required to pay an additional portion of their pensionable income. This portion is a two-year increase of 1% (2019) and 1% (2020). As of 2020, employees are contributing the entire 8% of their pensionable income.

    - The retirement formula is 2.7% at age 55 for IBEW and IBEW Supervisory employees hired on or before October 18, 2011. Effective November 1, 2017 employees were required to pay 2% of their total pensionable income with the City paying the remaining 6%. Effective each November 1st, employees will be required to pay an additional portion of their pensionable income. This portion is a three-year increase of 2% (2018), 2% (2019) and 2% (2020). As of November 2020, employees are contributing the entire 8% of their pensionable income.

- 2nd Tier - The retirement formula is 2.7% at age 55, and:
    - Miscellaneous employees, IBEW, and IBEW Supervisory hired on or after October 19, 2011 pay their share (8%) of contributions.

    - SEIU and SEIU Refuse employees hired on or after June 7, 2011 pay their share (8%) of contributions.

- 3rd Tier – The retirement formula is 2% at age 62 for new members hired on or after January 1, 2013 and the employee must pay the normal cost to CalPERS which is currently at 7.75%. Classic members (CalPERS members prior to 12/31/12) hired on or after January 1, 2013 may be placed in a different tier.

The contribution requirements of plan members and the City are established and may be amended by CalPERS.

6. EMPLOYEE RETIREMENT PLAN (CONTINUED)

BENEFITS PROVIDED

CalPERS provides service retirement and disability benefits, annual cost of living adjustments and death benefits to plan members, who must be public employees and beneficiaries. Benefits are based on years of credited service, equal to one year of full-time employment. Members with five years of total service are eligible to retire at age 50 with statutorily reduced benefits. All members are eligible for non-duty disability benefits after five years of service. The death benefit is one of the following: the Basic Death Benefit, the 1959 Survivor Benefit Level III, or the Optional Settlement 2W Death Benefit. The cost of living adjustments for the Plan are applied as specified by the Public Employees' Retirement Law.

EMPLOYEES COVERED

As of measurement date June 30, 2022 and June 30, 2021, the following employees, City-wide, were covered by the benefit terms of the Plan:

	Measurement Date	
	June 30, 2022	June 30, 2021
Inactive employees or beneficiaries currently receiving benefits	2,418	2,373
Inactive employees entitled to but not yet receiving benefits	1,475	1,422
Active employees	1,527	1,508

CONTRIBUTIONS

Section 20814(c) of the California Public Employees' Retirement Law requires that the employer contribution rates for all public employers be determined on an annual basis by the actuary and shall be effective on the July 1 following notice of a change in the rate. Funding contributions for the Plan is determined annually on an actuarial basis as of June 30 by CalPERS. The actuarially determined rate is the estimated amount necessary to finance the costs of benefits earned by employees during the year, with an additional amount to finance any unfunded accrued liability. The City is required to contribute the difference between the actuarially determined rate and the contribution rate of employees.

NET PENSION LIABILITY

The City's net pension liability for the Plan is measured as the total pension liability, less the pension plan's fiduciary net position. For fiscal year ended June 30, 2023, the net pension liability of the Plan is measured as of June 30, 2022, using an annual actuarial valuation as of June 30, 2021 rolled forward to June 30, 2022 using standard update procedures. For fiscal year ended June 30, 2022, the net pension liability of the Plan is measured as of June 30, 2021, using an annual actuarial valuation as of June 30, 2020 rolled forward to June 30, 2021 using standard update procedures. A summary of principal assumptions and methods used to determine the net pension liability is shown below.

ACTUARIAL ASSUMPTIONS

The total pension liabilities in the June 30, 2022 and 2021 actuarial valuations were determined using the following actuarial assumptions:

6. EMPLOYEE RETIREMENT PLAN (CONTINUED)

ACTUARIAL ASSUMPTIONS (CONTINUED)

	Miscellaneous Current Year	Miscellaneous Prior Year
Valuation Date	June 30, 2021	June 30, 2020
Measurement Date	June 30, 2022	June 30, 2021
Actuarial Cost Method	Entry-Age Normal Cost Method	Entry-Age Normal Cost Method
Actuarial Assumptions		
Discount Rate	6.90%	7.15%
Inflation	2.30%	2.50%
Salary Increase	Varies by entry age and service	Varies by entry age and service
Mortality Rate Table[1]	Derived using CalPERS' membership data for all funds.	
Post Retirement Benefit Increase	The lesser of contract COLA or 2.30% until Purchasing Power Protection Allowance floor on purchasing power applies, 2.30% thereafter	The lesser of contract COLA or 2.50% until Purchasing Power Protection Allowance floor on purchasing power applies, 2.50% thereafter

[1]The mortality table used was developed based on CalPERS-specific data. The probabilities of mortality are based on the 2021 CalPERS Experience Study for the period from 2001 to 2019. Pre-retirement and Post-retirement mortality rates include generational mortality improvement using 80% of Scale MP-2020 published by the Society of Actuaries. For more details on this table, please refer to the CalPERS Experience Study and Review of Actuarial Assumptions report from November 2021 that can be found on the CalPERS website.

LONG-TERM EXPECTED RATE OF RETURN

The long-term expected rate of return on pension plan investments was determined using a building-block method in which expected future real rates of return (expected returns, net of pension plan investment expense and inflation) are developed for each major asset class.

In determining the long-term expected rate of return, CalPERS took into account both short-term and long-term market return expectations. Using historical returns of all of the funds' asset classes, expected compound (geometric) returns were calculated over the next 20 years using a building-block approach. The expected rate of return was then adjusted to account for assumed administrative expenses of 10 Basis points. The expected real rates of return by asset class are as follows:

June 30, 2022 Measurement Date

Asset Class (1)	Assumed Asset Allocation	Real Return(1),(2)
Global Equity - Cap-weighted	30.00%	4.54%
Global Equity - Non-Cap-weighted	12.00%	3.84%
Private Equity	13.00%	7.28%
Treasury	5.00%	0.27%
Mortgage-backed Securities	5.00%	0.50%
Investment Grade Corporates	10.00%	1.56%
High Yield	5.00%	2.27%
Emerging Market Debt	5.00%	2.48%
Private Debt	5.00%	3.57%
Real Assets	15.00%	3.21%
Leverage	(5.00)%	(0.59)%

(1) An expected inflation of 2.30% used for this period.

(2) Figures are based on the 2021 Asset Liability Management study.

6. EMPLOYEE RETIREMENT PLAN (CONTINUED)

LONG-TERM EXPECTED RATE OF RETURN (CONTINUED)

June 30, 2021 Measurement Date

Asset Class (1)	Current Target Allocation	Real Return Years 1 - 10 (2)	Real Return Years 11+ (3)
Global Equity	50.0%	4.80%	5.98%
Fixed Income	28.0%	1.00%	2.62%
Inflation Assets	0.0%	0.77%	1.81%
Private Equity	8.0%	6.30%	7.23%
Real Assets	13.0%	3.75%	4.93%
Liquidity	1.0%	0.00%	-0.92%

(1) In the System's ACFR, Fixed Income is included in Global Debt Securities; Liquidity is included in Short-term Investments; Inflation Assets are included in both Global Equity Securities and Global Debt Securities.

(2) An expected inflation of 2.00% used for this period.

(3) An expected inflation of 2.92% used for this period.

DISCOUNT RATE

The discount rate used to measure the total pension liability was 6.90% and 7.15% for measurement dates as of June 30, 2022 and 2021, respectively. The projection of cash flows used to determine the discount rate assumed that contributions from plan members will be made at the current member contribution rates and that contributions from employers will be made at statutorily required rates, actuarially determined. Based on those assumptions, the Plan's fiduciary net position was projected to be available to make all projected future benefit payments of current plan members. Therefore, the long-term expected rate of return on plan investments was applied to all periods of projected benefit payments to determine the total pension liability.

CHANGES IN ASSUMPTIONS

Effective with the June 30, 2021 valuation date (2022 measurement date), the accounting discount rate was reduced from 7.15% to 6.90%. In determining the long-term expected rate of return, CalPERS took into account long-term market return expectations as well as the expected pension fund cash flows. Projected returns for all asset classes are estimated, combined with risk estimates, and are used to project compound (geometric) returns over the long term. The discount rate used to discount liabilities was informed by the long-term projected portfolio return. In addition, demographic assumptions and the inflation rate assumption were changed in accordance with the 2021 CalPERS Experience Study and Review of Actuarial Assumptions.

CHANGES IN THE NET PENSION LIABILITY (ASSET)

The changes in the Water Utility's proportionate share of the net pension liability/(asset) as of June 30, 2023 (measurement date June 30, 2022) and 2022 (measurement date June 30, 2021) for the Plan are as follows:

June 30, 2023		Net Pension Liability/ (Asset)	Proportion of the Plan
Proportion - Reporting date June 30, 2023 (Measurement Date June 30, 2022)	$	12,854	9.76 %
Proportion - Reporting date June 30, 2022 (Measurement Date June 30, 2021)		(8,809)	9.93 %
Changes - Increase / (Decrease)		21,663	(0.17)%
June 30, 2022			
Proportion - Reporting date June 30, 2022 (Measurement Date June 30, 2021)	$	(8,809)	9.93 %
Proportion - Reporting date June 30, 2021 (Measurement Date June 30, 2020)		12,203	10.16 %
Changes - Increase / (Decrease)		(21,012)	-0.23 %

6. EMPLOYEE RETIREMENT PLAN (CONTINUED)

PENSION EXPENSES AND DEFERRED OUTFLOWS/INFLOWS OF RESOURCES RELATED TO PENSION

For the fiscal years ended June 30, 2023 and 2022, the Water Utility recognized pension expense/(income) of $2,373 and $(2,176), respectively. At June 30, 2023 and 2022, the Water Utility reported deferred outflows of resources and deferred inflows of resources related to pension from the following sources:

	June 30, 2023		June 30, 2022	
	Deferred Outflows of Resources	Deferred Inflows of Resources	Deferred Outflows of Resources	Deferred Inflows of Resources
Pension contributions subsequent to measurement date	$ 2,844	$ -	$ 2,715	$ -
Change of assumptions	1,321	-	-	-
Difference between expected and actual expense	87	(1,187)	365	-
Net difference between projected and actual earnings on pension plan investments	7,336	-	-	(14,814)
Total	$ 11,588	$ (1,187)	$ 3,080	$ (14,814)

Deferred outflows of resources related to contributions subsequent to the measurement date reported in prior year was recognized as a reduction of the net pension liability in the year ended June 30, 2023.

The remaining amounts reported as deferred outflows of resources and deferred (inflows) of resources related to pensions will be recognized as pension expense as follows:

Year Ended June 30	Deferred Outflows/ (Inflows) of Resources
2024	$ 1,343
2025	1,151
2026	497
2027	4,566
Total	$ 7,557

Subsequent Events - On July 12, 2021, CalPERS reported a preliminary 21.3% net return on investments for fiscal year 2020-21. Based on the thresholds specified in CalPERS Funding Risk Mitigation policy, the excess return of 14.3% prescribes a reduction in investment volatility that corresponds to a reduction in the discount rate used for funding purposes of 0.20%, from 7.00% to 6.80%. Since CalPERS was in the final stages of the four-year Asset Liability Management (ALM) cycle, the board elected to defer any changes to the asset allocation until the ALM process concluded, and the board could make its final decision on the asset allocation in November 2021.

On November 17, 2021, the board adopted a new strategic asset allocation. The new asset allocation along with the new capital market assumptions, economic assumptions and administrative expense assumption support a discount rate of 6.90% (net of investment expense but without a reduction for administrative expense) for financial reporting purposes. This includes a reduction in the price inflation assumption from 2.50% to 2.30% as recommended in the November 2021 CalPERS Experience Study and Review of Actuarial Assumptions. This study also recommended modifications to retirement rates, termination rates, mortality rates and rates of salary increases that were adopted by the board. These new assumptions will be reflected in the GASB 68 accounting valuation reports for the June 30, 2022, measurement date.

6. EMPLOYEE RETIREMENT PLAN (CONTINUED)

SENSITIVITY OF THE NET PENSION LIABILITY (ASSET) TO CHANGES IN THE DISCOUNT RATE

The following presents the Water Utility's proportionate share of the net pension liability of the Plan, calculated using the discount rate of 6.90% (measurement date June 30, 2022), and 7.15% (measurement date June 30, 2021) as well as what the Water Utility's proportionate share of the net pension liability would be if it was calculated using a discount rate that is 1-percentage point lower or 1-percentage point higher than the current rate:

	Measurement Date June 30, 2022			Measurement Date June 30, 2021		
	Discount Rate -1% (5.90%)	Current Discount Rate (6.90%)	Discount Rate +1% (7.90%)	Discount Rate -1% (6.15%)	Current Discount Rate (7.15%)	Discount Rate +1% (8.15%)
Water Utility's proportionate share of the Plan's net pension liability/(asset)	$ 34,227	$ 12,854	$ (4,696)	$ 11,807	$ (8,809)	$ (25,787)

Detailed information about the Plan's fiduciary net position is available in the separately issued CalPERS financial reports.

7. OTHER POST-EMPLOYMENT BENEFITS (OPEB)

PLAN DESCRIPTION

The City's defined benefit OPEB plan, Retiree Health Plan, provides continuation of medical (including prescription drugs) and dental coverage benefits to retirees and surviving spouses in the form of an implied rate subsidy. The Retiree Health Benefits plan is a single employer defined benefit OPEB plan administered by the City. No assets are accumulated in a trust that meets the criteria in paragraph 4 of GASB Statement No. 75.

BENEFITS PROVIDED

Eligibility for continuation of coverage requires retirement from the City and CalPERS with at least 5 years of City service. The retiree is responsible for 100% of the premium cost for coverage, which is based on the blended experience of both the active and retired employees. The City is not required by law or contractual agreement to provide funding other than the pay-as-you-go amount necessary to provide current benefit to eligible retirees and beneficiaries. Retiree and spousal coverage terminates when the retiree becomes covered under another employer health plan, or when the retiree reaches Medicare eligibility age, which is currently age 65. However, retiree benefit continues to the surviving spouse if the retiree elects the CalPERS survivor annuity.

As of measurement date June 30, 2022 and 2021, the following employees, City-wide, were covered by the benefit terms:

	Measurement Date June 30, 2022	Measurement Date June 30, 2021
Inactive plan members or beneficiaries currently receiving benefits	206	206
Inactive plan members entitled to but not yet receiving benefits	-	-
Active plan members	2,014	2,014

7. OTHER POST-EMPLOYMENT BENEFITS (OPEB) (CONTINUED)

ACTUARIAL ASSUMPTIONS

The total OPEB liability was determined by actuarial valuation as of June 30, 2022 and 2021, using the following actuarial assumptions:

	Miscellaneous - Current Year	Miscellaneous - Prior Year
Valuation Date	June 30, 2021	June 30, 2021
Measurement Date	June 30, 2022	June 30, 2021
Actuarial Cost Method	Pay-as-you-go for implicit rate subsidy	Pay-as-you-go for implicit rate subsidy
Actuarial Assumptions		
Discount Rate	Bond Buyer 20 Index at June 30, 2022 resulting in a rate of 3.54%	Bond Buyer 20 Index at June 30, 2021 resulting in a rate of 2.16%
Inflation Rate	2.50% per annum	2.75% per annum
Payroll Increases	2.75% per year. Since benefits do not depend on salary (as they do for pensions), this assumption is only used to determine the accrual pattern of the Actuarial Present Value of Projected Benefit Payments.	2.75% per year. Since benefits do not depend on salary (as they do for pensions), this assumption is only used to determine the accrual pattern of the Actuarial Present Value of Projected Benefit Payments.
Mortality	2017 CalPERS Retiree Mortality Table for the appropriated population	2017 CalPERS Retiree Mortality Table for the appropriated population
Healthcare Trend Rates	Medical trend in future years has been updated to 4.00% for all years from 6.25% tiered down by 0.25% per year to 4.50% in all future years.	Medical trend in future years has been updated to 4.00% for all years from 6.25% tiered down by 0.25% per year to 4.50% in all future years.

CHANGES OF ASSUMPTIONS

In 2022, the discount rate was changed from 2.16% to 3.54%.

SENSITIVITY OF TOTAL OPEB LIABILITY TO CHANGES IN HEALTHCARE COST TREND RATES

The following presents the Water Utility's proportionate share of the City's total OPEB liability, calculating using the healthcare trend rate of 4% for measurement date as of June 30, 2022 and June 30, 2021, as well as what the Water Utility's total OPEB liability would be if it was calculated using a healthcare cost trend rate that is 1-percentage-point lower or 1-percentage-point higher than the current rate:

	Measurement Date June 30, 2022			Measurement Date June 30, 2021		
	1% Decrease	Current healthcare cost trend rate 4%	1% Increase	1% Decrease	Current healthcare cost trend rate 4%	1% Increase
Water Utility's proportionate share of the total OPEB liability	$ 3,546	$ 4,043	$ 4,609	$ 3,771	$ 4,286	$ 4,896

7. OTHER POST-EMPLOYMENT BENEFITS (OPEB) (CONTINUED)

SENSITIVITY OF TOTAL OPEB LIABILITY TO CHANGES IN DISCOUNT RATES

The following presents the Water Utility's proportionate share of the City's total OPEB liability, calculating using the discount rate of 3.54% and 2.16% for measurement date as of June 30, 2022 and 2021 respectively, as well as what the Water Utility's total OPEB liability would be if it was calculated using a discount rate that is 1-percentage-point lower or 1-percentage-point higher than the current rate:

	Measurement Date June 30, 2022			Measurement Date June 30, 2021		
	1% Decrease (2.54%)	Current Discount Rate (3.54%)	1% Increase (4.54%)	1% Decrease (1.16%)	Current Discount Rate (2.16%)	1% Increase (3.16%)
Water Utility's proportionate share of total OPEB liability	$ 4,432	$ 4,043	$ 3,769	$ 4,652	$ 4,286	$ 3,946

CHANGE IN TOTAL OPEB LIABILITY

For fiscal year ended June 30, 2023 and 2022, the Water Utility recognized total OPEB expense of $168 and $210 respectively. The following table shows the change in the Water Utility's proportionate share of the City's total OPEB liability for the year ended June 30, 2023 (measurement date June 30, 2022) and the year ended June 30, 2022 (measurement date June 30, 2021):

June 30, 2023	Total OPEB Liability	Proportion of the City
Proportion - Reporting date June 30, 2023 (Measurement Date June 30, 2022)	$ 4,043	8.89 %
Proportion - Reporting date June 30, 2022 (Measurement Date June 30, 2021)	4,286	8.79 %
Changes - Increase / (Decrease)	(243)	0.10 %
June 30, 2022		
Proportion - Reporting date June 30, 2022 (Measurement Date June 30, 2021)	$ 4,286	8.79 %
Proportion - Reporting date June 30, 2021 (Measurement Date June 30, 2020)	4,550	8.70 %
Changes - Increase / (Decrease)	(264)	0.09 %

DEFERRED OUTFLOWS/INFLOWS OF RESOURCES RELATED TO OPEB

At June 30, 2023, the Water Utility reported deferred inflows of resources related to OPEB from the following sources:

	Deferred Outflows of Resources	Deferred Inflows of Resources
Difference between expected and actual expense	$ 12	$ (255)
Change of assumptions	509	(634)
Contributions subsequent to measurement date	123	-
Total	$ 644	$ (889)

7. OTHER POST-EMPLOYMENT BENEFITS (OPEB) (CONTINUED)

DEFERRED OUTFLOWS/INFLOWS OF RESOURCES RELATED TO OPEB (CONTINUED)

Amounts reported as deferred inflows of resources related to OPEB will be recognized in OPEB expense as follows:

Year Ended June 30	Deferred Outflows/ (Inflows) of Resources
2024	$ (10)
2025	(10)
2026	6
2027	8
2028	8
Thereafter	(370)
Total	$ (368)

8. RESTRICTED NET POSITION

Pursuant to applicable bond indentures, a reserve for debt service has been established by restricting assets and reserving a portion of net position. Bond indentures for the Water Utility's water revenue and refunding bonds require debt service reserves that equate to the maximum annual debt service required in future years and bond service reserves of three months interest and nine months principal due in the next fiscal year. Variable rate revenue and refunding bonds require 110% of the monthly accrued interest to be included in the reserve. Certain issues have no debt service reserve requirements (2009B, 2011A, 2019A and 2022A).

9. CONSTRUCTION COMMITMENTS

As of June 30, 2023, the Water Utility had commitments (encumbrances) of approximately $10,834 with respect to ongoing capital projects, of which $10,077 is expected to be funded by bonds, and $757 to be funded by unrestricted reserves.

10. LITIGATION

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

CITY OF RIVERSIDE V. BLACK & DECKER (U.S.), INC.

The Water Utility is a plaintiff in a lawsuit against several entities that either owned or leased a property site in the City of Colton and City of Rialto that is contaminated by perchlorate. The lawsuit was filed March 31, 2009. On May 24, 2018, the State trial court dismissed the action, with prejudice, for failure to join the federal Department of Defense, with instructions to refile the lawsuit in federal court and include the Department of Defense as a party. The City has appealed such dismissal, and on May 6, 2020, the appellate court overturned the trial court's dismissal. The appellate court remanded the case back to the trial court and the parties are now waiting for the trial court to set a trial date. The City has reached settlement with two of the defendants: Trojan Fireworks Company and Zambelli and those defendants have been dismissed from the lawsuit.

PONGS V. CITY OF RIVERSIDE ("PONGS I")

On December 16, 2019, a lawsuit entitled Pongs v. City of Riverside was filed against the City challenging the City's Water Rate WA-12, "Agricultural Water", alleging that the City is overcharging customers for service under this rate in violation of Article XIIID, Section 6 of the California Constitution. The plaintiff is seeking that the court invalidate Water Rate WA-12 and refund all to all WA-12 customers monies collected under that rate. A hearing date for the first phase of the trial, on liability, has been scheduled for November 17, 2021. This lawsuit has been stayed pending the resolution of another lawsuit challenging the City's Water General Fund Transfer, entitled *Simpson v. City of Riverside* (as referenced below).

10. LITIGATION (CONTINUED)

SIMPSON V. CITY OF RIVERSIDE

On December 19, 2019, a class action lawsuit entitled Simpson v. City of Riverside was filed against the City alleging that the City is overcharging customers for water utility service in violation of Article XIIID, Section 6 of the California Constitution, on the grounds that the City is transferring 11.5% of water utility revenues to the City's general fund. The transfer, also known as the "General Fund Transfer", was approved by voters on June 4, 2013, as a general tax. The plaintiff is seeking refunds for all customers for monies collected in violation and also that the court set aside the voter's 2013 approval of the General Fund Transfer. The trial was bifurcated into two phases, liability and damages. The Court issued its ruling on the liability phase on August 17, 2023, finding that the City's water rates violated Article XIID, Section 6 of the California Constitution because they were set in an amount sufficient to recover the General Fund Transfer. A trial date of April 3, 2024 has been set for the second phase of the trial regarding damages.

CITY OF RIVERSIDE V. 3M COMPANY, ET AL.

The Water Utility is a plaintiff in a lawsuit against several entities over contamination of its water supply wells with synthetic per- and polyfluoroalkyl substances ("PFAS"). The lawsuit was filed July 26, 2021 as part of a multidistrict litigation proceeding consolidated before a federal judge in Charleston, South Carolina. No trial date has been set.

CITY OF RIVERSIDE V. SHELL OIL COMPANY, ET AL.

The Water Utility is a plaintiff in a lawsuit against several entities over contamination of its water supply wells with 1, 2, 3, -Trichloropropane ("TCP"). The lawsuit was filed December 4, 2020, in the superior court in San Francisco. No trial date has been set.

PONGS ET AL. V. CITY OF RIVERSIDE ET AL. ("PONGS III")

On December 22, 2022, a lawsuit entitled Pongs et al. v. City of Riverside et al. was filed against the City by two water customers challenging the City's issuance of water revenue bonds, alleging that the issuance of the bonds violated Proposition 218 because the City had agreed to fix and raise rates to pay for the costs of debt service on the bonds and the bonds improperly required water customers to pay for pension liabilities of retired City employees. The trial was conducted on August 18, 2023. The Court ruled in favor of the City on all causes of action. To date, no appeal has been filed.

PONGS ET AL. V. CITY OF RIVERSIDE ET AL. ("PONGS IV")

On March 3, 2023, a lawsuit entitled Pongs, et al. v. City of Riverside, was filed against the City by a water customer as an individual and seeking class action certification, alleging that the City improperly acquired shares in the Gage Canal Company in breach of the Gage Canal Operating Agreement entered into on June 9, 1965. Plaintiff seeks return of the Gage Canal shares to all shareholders improperly divested of shares and that the Court enjoin the City from continuing its current practice to acquire ownership of Gage Canal shares. No trial date has been set in this matter.

11. LEASES AND SUBSCRIPTION-BASED INFORMATION TECHNOLOGY ARRANGEMENTS

For the year ended June 30, 2022, the financial statements included the adoption of GASB Statement No. 87, *Leases.* The primary objective of this statement is to enhance the relevance and consistency of information about governments' leasing activities. This statement establishes a single model for lease accounting based on the principle that leases are financings of the right to use an underlying asset. Under this statement, a lessee is required to recognize a lease liability and a lease asset, and a lessor is required to recognize a lease receivable and a deferred inflow of resources. For additional information, refer to the disclosures below.

For the year ended June 30, 2023, the financial statements include the adoption of GASB Statement No. 96, *Subscription-Based Information Technology Agreements* (SBITA). This Statement defines SBITA as a contract that conveys control of the right to use another party's information technology software, alone or in a combination with tangible capital asset, as specified in a contract for a period of time in an exchange or exchange-like transaction. For additional information, refer to the disclosures below.

LEASES PAYABLE

The Water Utility has 4 leases as Lessee for the use of various pieces of machinery and equipment as of the end of the fiscal year. The Water Utility is required to make principal and interest payments through fiscal year 2026. An initial lease liability was recorded in the amount of $25. As of June 30, 2023, the value of the lease liability is $14. The leases have an interest rate of 0.52%. The value of the lease asset as of June 30, 2023 is $21 with accumulated amortization of $10 and is included with machinery and equipment on the Asset Class activities table found below.

	Amount of Lease Assets by Major Classes of Underlying Asset	
Asset Class	**Lease Asset Value**	**Accumulated Amortization**
Machinery and equipment	$ 21	$ (10)
Total	$ 21	$ (10)

Fiscal Year	Principal Payments	Interest Payments	Total Payments
2024	$ 5	$ -	$ 5
2025	4	-	4
2026	3	-	3
Total	$ 12	$ -	$ 12

11. LEASES AND SUBSCRIPTION-BASED INFORMATION TECHNOLOGY ARRANGEMENTS (CONTINUED)

LEASES RECEIVABLE

The Water Utility has 22 leases as a Lessor for the use of various pieces of land and building as of the end of the fiscal year. The terms range from 2 to 110 years beginning on the contract commencement date. An initial lease receivable was recorded in the amount of $83,950. As of June 30, 2023, the value of the lease receivable is $85,386. The leases have interest rates ranging from 0.52% to 2.81%. The value of the deferred inflow of resources as of June 30, 2023 was $84,102, and the Water Utility recognized lease revenue of $1,708 during the fiscal year.

Fiscal Year	Principal Payments	Interest Payments	Total Payments
2024	$ 1,001	$ 1,531	$ 2,532
2025	1,027	1,507	2,534
2026	1,046	1,486	2,532
2027	745	1,466	2,211
2028	469	1,460	1,929
2029-2033	2,286	7,157	9,443
2034-2038	2,259	6,957	9,216
2039-2043	2,342	6,753	9,095
2044-2048	2,824	6,525	9,349
2049-2053	3,407	6,243	9,650
2054-2058	4,089	5,908	9,997
2059-2063	4,803	5,508	10,311
2064-2068	5,204	5,052	10,256
2069-2073	2,855	4,698	7,553
2074-2078	3,046	4,433	7,479
2079-2083	3,331	4,148	7,479
2084-2088	3,641	3,838	7,479
2089-2093	3,984	3,494	7,478
2094-2098	4,356	3,121	7,477
2099-2103	4,766	2,711	7,477
2104-2108	5,209	2,267	7,476
2109-2113	5,698	1,777	7,475
2114-2118	6,232	1,243	7,475
2119-2123	6,815	659	7,474
2124-2128	3,951	118	4,069
Total	$ 85,386	$ 90,060	$ 175,446

SUBSCRIPTION-BASED INFORMATION TECHNOLOGY ARRANGEMENTS PAYABLE

The Water Utility has 2 subscription-based information technology arrangements (SBITA) for the use of various software as of the end of the fiscal year. The Water Utility is required to make principal and interest payments through fiscal year 2025. An initial lease liability was recorded in the amount of $32. As of June 30, 2023, the value of the subscription liability was $17. The subscriptions have interest rate of 0.52%. The value of the subscription asset as of June 30, 2023 of $32 with accumulated amortization of $15.

Fiscal Year	Principal	Interest	Total Payments
2024	$ 15	$ -	$ 15
2025	2	-	2
Total	$ 17	$ -	$ 17

WATER UTILITY
KEY HISTORICAL OPERATING DATA

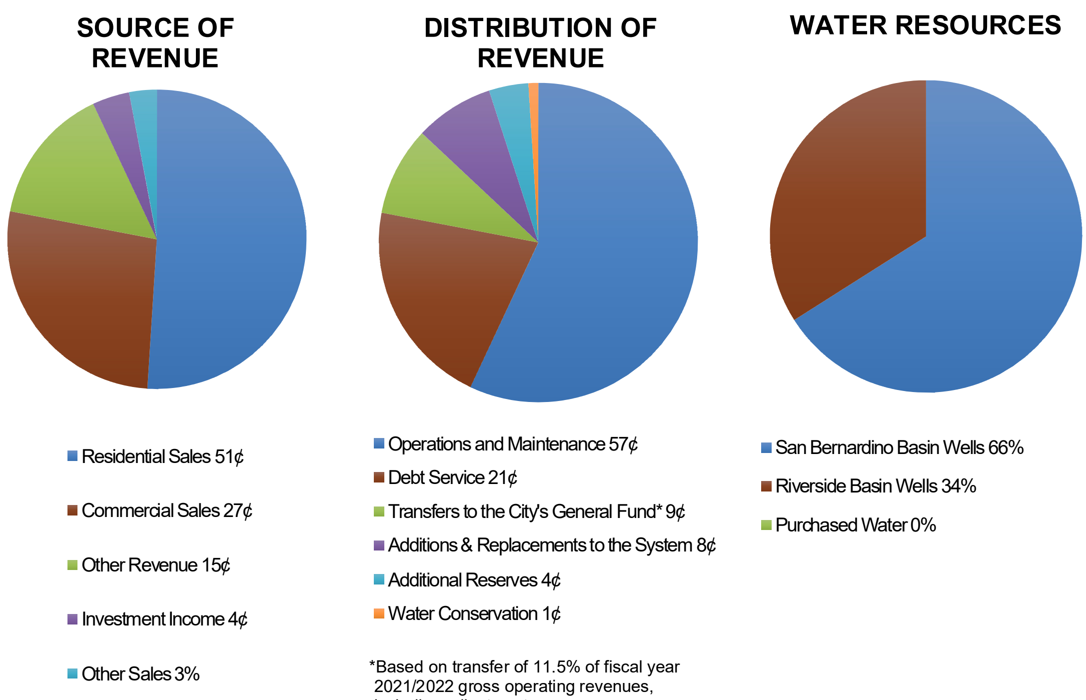
Fiscal Year	2022/23	2021/22	2020/21	2019/20	2018/19
WATER SUPPLY (ACRE FEET)					
Potable water production[1]	60,185	68,054	72,215	64,827	64,379
Percentage pumped (%)[2]	100	100	100	100	100
System peak day (gallons)[3]	81,800,000	82,700,000	91,900,000	89,600,000	90,200,000
WATER USE					
Number of meters as of year end:					
Residential	59,907	59,876	59,782	59,598	59,456
Commercial/Industrial	6,175	6,153	6,080	6,068	6,028
Other	359	343	336	365	319
Total	66,441	66,372	66,198	66,031	65,803
CCF* sales:					
Residential	13,078,242	15,362,908	16,149,357	14,610,481	14,157,606
Commercial/industrial[4]	9,003,457	10,245,377	10,069,176	9,126,132	9,191,682
Other[4]	764,265	870,928	835,300	787,119	805,022
Subtotal	22,845,964	26,479,213	27,053,833	24,523,732	24,154,310
Wholesale	821,502	366,370	1,571,549	1,002,289	1,673,411
Total	23,667,466	26,845,583	28,625,382	25,526,021	25,827,721

*(CCF equals 100 cubic feet)

WATER FACTS					
Average annual CCF per residential customer	218	257	270	245	238
Average price ($/CCF) per residential customer	$ 3.38	$ 2.98	$ 2.77	$ 2.67	$ 2.50
Debt service coverage ratio (DSC)[5, 6, 7, 8]	1.93	2.23	2.25	1.80	1.68
Employees[9]	165	164	165	165	159

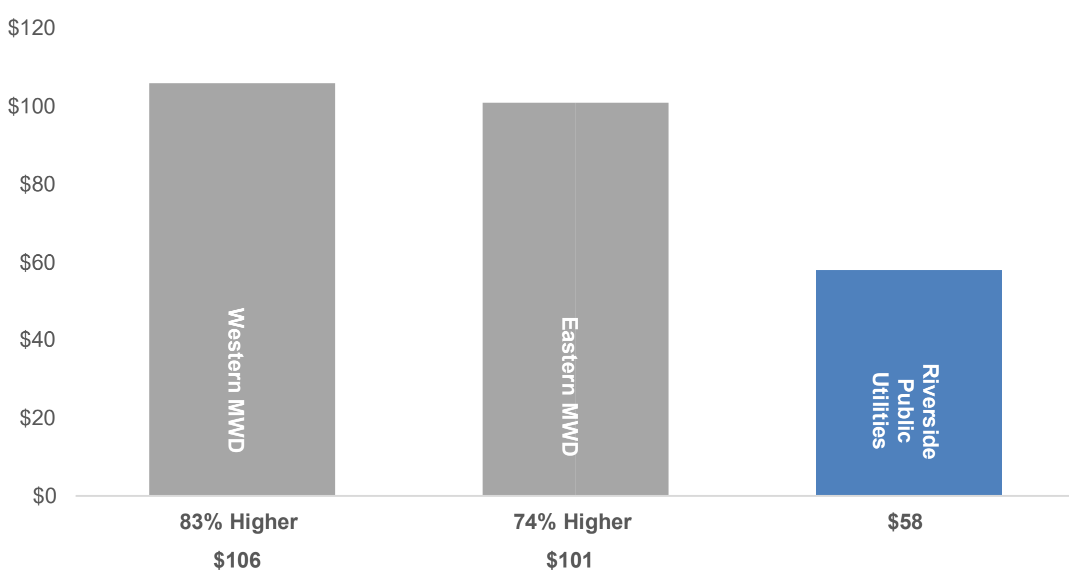
[1] Water pumping figures have been adjusted to include retail and wholesale potable water production.
[2] No purchased water.
[3] System peak day has been adjusted to reflect production for retail customers.
[4] Changes in fiscal years 18/19 & 19/20 reflect reclassification of certain Commercial/Industrial accounts and Other accounts in connection with current Water Rate Plan.
[5] Interest expense used to calculate DSC is net of federal subsidy on Build America Bonds.
[6] Excludes GASB 68 Accounting and Financial Reporting for Pension non-cash adjustments of ($471), ($4,891), ($1,107), $1,046, and ($482) for fiscal years 22/23 through FY18/19, respectively.
[7] Excludes GASB 75 Accounting and Financial Reporting for Postemployment Benefits Other Than Pensions non-cash adjustments of 168, $210, $73, $197, and $118, for fiscal years 22/23 through FY 18/19, respectively.
[8] Includes GASB 87 *Leases* net revenue adjustments of $728 and $708 for fiscal years 22/23 and 21/22, respectively.
[9] Approved positions.

2022/2023 WATER REVENUE AND RESOURCES



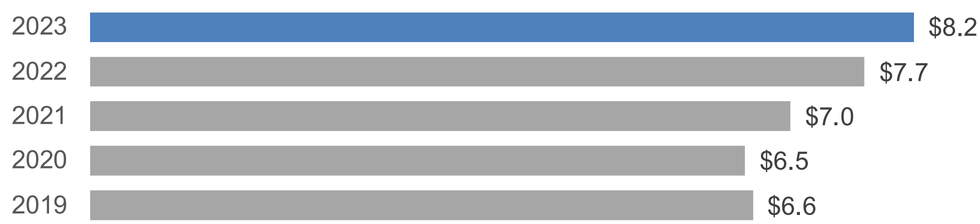
*Based on transfer of 11.5% of fiscal year 2021/2022 gross operating revenues, including adjustments

RESIDENTIAL WATER RATE COMPARISON - 21 CCF PER MONTH (AS OF JUNE 30, 2023)

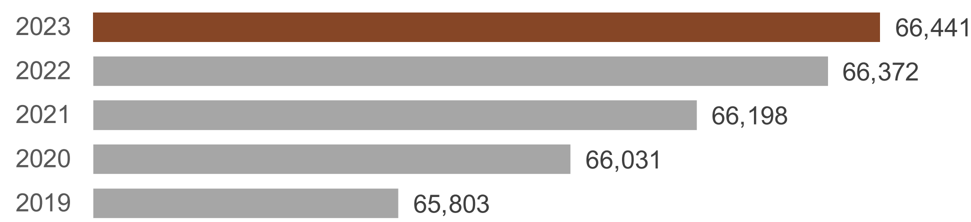


WATER KEY OPERATING INDICATORS

General Fund Transfer (In Millions)

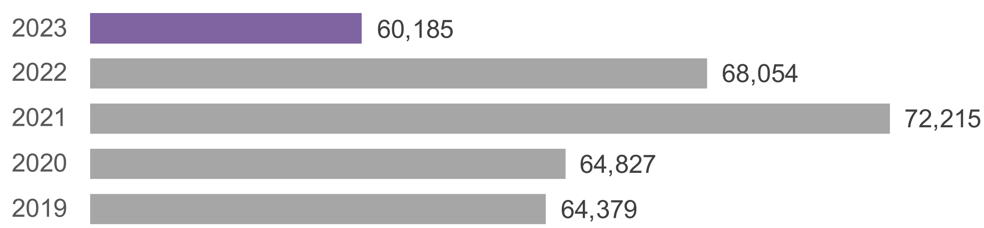


Number of Meters At Year End

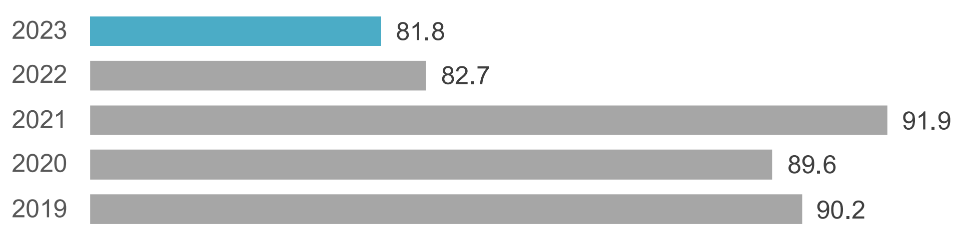


Total Operating Revenue (In Millions)

Potable Water Production (In Acre Feet)



Peak Day Demand (In Millions of Gallons)



WATER FACTS AND SYSTEM DATA

Established	1913
Service Area Population	313,676
Service Area Size (square miles)	74.24

System Data:

Smallest Pipeline	2.0"
Largest Pipeline	72.0"
Miles of Pipeline	993
Number of Domestic Wells	53
Number of Active Reservoirs	16
Total Reservoir Capacity (gallons)	108,500,000
Number of Treatment Plants	6
Number of Treatment Vessels	84
Miles of Canal	14
Number of Fire Hydrants	8,023
Daily Average Production (gallons)	57,600,000
2022-2023 Peak Day (gallons) 07/18/22, 101 Degrees	81,800,000
Historical Peak (gallons) 08/9/05, 99 Degrees	118,782,000

Bond Ratings:

Fitch Ratings	AA+
Moody's	Aa2
S&P Global Ratings	AA+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