ANNUAL REPORT
(Pursuant to S.E.C. Rule 15c2-12)
December 30, 2025

Relating to:
$80,795,000 Southern California Public Power Authority
Natural Gas Project A, 2008 Revenue Bonds (Taxable)
(City of Anaheim, California)

INTRODUCTION

This Annual Report is filed pursuant to the Continuing Disclosure Resolution (Resolution No. 2007-67), adopted by the Southern California Public Power Authority (the "Authority" or "SCPPA") on December 20, 2007 (the "Disclosure Resolution"), in accordance with Securities and Exchange Commission Rule 15c2-12 (the "Rule"). This Annual Report relates to the above-captioned bonds (the "Bonds"). The Bonds are described in the Authority's Official Statement dated January 24, 2008 (the "Official Statement"). The Bonds were issued to finance, among other things, the costs of acquisition and development of certain natural gas resources, reserves, fields, wells, and related facilities as well as certain capital improvements related thereto. Except as otherwise provided herein, terms used herein that are not defined herein have the meanings ascribed to such terms in the Official Statement.

The information in this Annual Report is provided in order to comply with the Authority's contractual commitment established by the Disclosure Resolution to provide certain of the information specified therein. Certain information in this Annual Report is not required to be provided by the Disclosure Resolution. By providing such information, the Authority does not undertake or agree to provide such information in any future year. The Authority and the City of Anaheim, California ("Anaheim") make no representation that this Annual Report contains all information material to a decision to purchase or sell any of the Bonds.

The information set forth herein has been furnished by the Authority and Anaheim and includes information obtained from other sources, which is believed to be reliable. Any statements herein involving matters of opinion or estimates, whether or not so expressly stated, are set forth as such and not as representations of fact, and no representation is made that such opinion or estimates will be realized. The information and expressions of opinion contained in this Annual Report are provided as of the respective dates specified herein and are subject to change without notice, and the filing of this Annual Report shall not, under any circumstances, create any implication that there has been no change in the affairs of the Authority or any Participant (as defined below) or in the other matters described herein since the date as of which such information is provided.

THE NATURAL GAS PROJECT

General Description

The Natural Gas Project includes the Authority's leasehold interests in (i) certain natural gas resources, reserves, fields, wells and related facilities located near Pinedale, Wyoming (the "Wyoming Subproject") and (ii) certain natural gas resources, reserves, fields, wells and related facilities in (or near) the Barnett Shale geological formation in Texas (the "Texas Subproject," and collectively with the Wyoming Subproject, the "Natural Gas Project" or the "Project"). The Authority has sold to each of Anaheim and the Cities of Burbank, Colton, Glendale and Pasadena, California (collectively, the "Participants") a portion of the entire production capacity of its leasehold interests, as a source of long-term supply of Gas at a more levelized price to provide fuel for their generation needs, on a "take-or-pay" basis through gas sales agreements with each of the Participants. The Bonds are payable only from amounts received by SCPPA from Anaheim. Anaheim has taken delivery of Gas from the Wyoming Subproject since 2005 and has taken delivery of Gas from the Texas Subproject since 2006.

Pinedale Leases

Output, Gathering and Processing. The wells have historically produced approximately 95% natural gas and 5% Oil. The Oil is removed at the surface and trucked to a refinery, and the dry gas is delivered into a gathering pipeline system and transported to a processor for removal of natural gas liquids ("NGLs"). The processor delivers pipeline-quality gas to the interstate pipeline. Proceeds from the sale of gas in Wyoming financed the purchase of approximately 84,510 MMBtu at SoCal City Gate during fiscal year ended June 30, 2025.

Barnett Leases

Output; Gathering, Processing, Marketing and Distribution; Delivery to Participants. The wells produce approximately 71% natural gas, 28% NGLs, and 1% Oil. The Oil is removed at the surface and trucked to a refinery, and the dry gas is delivered into a gathering pipeline system and transported to a processor for removal of NGLs. The processor delivers pipeline-quality gas to the interstate pipeline. Proceeds from the sale of gas in Texas financed the purchase of approximately 145,842 MMBtu at SoCal City Gate during fiscal year ended June 30, 2025.

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Certain Financial Statements Relating to the Natural Gas Project

The following Statement of Net Position has been prepared by the Authority based upon audited financial statements of the Authority for fiscal years ended June 30, 2025 and June 30, 2024.

Southern California Public Power Authority
Natural Gas Project Pinedale & Barnett
Statement of Net Position
(In Thousands)

	Fiscal Year Ended June 30,	
	2025	**2024**
ASSETS		
Noncurrent assets		
Net utility plant	$34,537	$39,951
Investments – restricted	40,488	37,249
Investments - unrestricted	1,000	700
Prepaid and other assets	126	126
Total noncurrent assets	76,151	78,026
Current assets		
Cash and cash equivalents – restricted	6,301	7,862
Cash and cash equivalents – unrestricted	5,130	4,877
Interest receivable	386	434
Accounts receivable	837	1,869
Prepaid and other assets	512	513
Total current assets	13,166	15,555
DEFERRED OUTFLOWS OF RESOURCES		
Reclamation and decommissioning obligation	332	378
Total deferred outflows of resources	332	378
Total assets and deferred outflows of resources	$89,649	$93,959
LIABILITIES		
Noncurrent liabilities		
Long-term debt	$23,330	$27,165
Advances from participants	9,118	11,300
Reclamation and decommissioning obligation	2,143	2,087
Total noncurrent liabilities	34,591	40,552
Current liabilities		
Debt due within one year	3,835	4,025
Advances from participant due within one year	4,248	4,188
Accrued interest	808	921
Accounts payable and accruals	2,149	2,228
Accrued property tax	91	50
Total current liabilities	11,131	11,412
Total liabilities	45,722	51,964

NET POSITION		
Net investment in capital assets	34,537	22,627
Restricted	20,271	15,058
Unrestricted	(10,881)	4,310
Total net position	43,927	41,995
Total liabilities and net position	$89,649	$93,959

The following Statement of Revenues, Expenses and Changes in Net Position has been prepared by the Authority based upon audited financial statements of the Authority for fiscal years ended June 30, 2025 and June 30, 2024.

Southern California Public Power Authority
Natural Gas Project Pinedale & Barnett
Statement of Revenues, Expenses and Changes in Net Position
(In Thousands)

	Fiscal Year Ended June 30,	
	2025	**2024**
Operating revenues:		
Sales of natural gas	$10,232	$11,954
Total operating revenues	10,232	11,954
Operating expenses:		
Operations and maintenance	3,374	3,444
Depreciation, depletion, and amortization	5,423	3,703
Decommissioning	47	47
Total operating expenses	8,844	7,194
Operating income	1,388	4,760
Non-operating revenues (expenses)		
Investment and other income	2,217	2,371
Inflation of decommissioning liability	(56)	(61)
Other interest and debt expense	(1,617)	(1,843)
Net non-operating revenues (expenses)	544	467
Change in net position	1,932	5,227
Net position – beginning of year	41,995	36,768
Net position – end of year	$43,927	$41,995

DEBT SERVICE REQUIREMENTS FOR THE BONDS

The debt service requirements for the Bonds are as follows:

Year Ending July 1	Principal	Interest	Total
2026	$2,105,000.00	$788,690.00	$2,893,690.00
2027	2,020,000.00	663,863.50	2,683,863.50
2028	1,955,000.00	544,077.50	2,499,077.50
2029	1,885,000.00	428,146.00	2,313,146.00
2030	1,830,000.00	316,365.50	2,146,365.50
2031	1,775,000.00	207,846.50	1,982,846.50
2032	1,730,000.00	102,589.00	1,832,589.00
Total	$13,300,000.00	$3,051,578.00	$16,351,578.00

FINANCIAL STATEMENTS

The audited financial statements of the Authority and Anaheim for the fiscal year ended June 30, 2025 are attached hereto.

MISCELLANEOUS; MOST RECENT AUTHORITY OFFICIAL STATEMENT

The historical information set forth in this Annual Report is not necessarily indicative of future results or performance due to various factors, including, among others, those discussed in the Authority's Official Statement, dated July 9, 2025, relating to the Southern Transmission System Renewal Project, Revenue Bonds, 2025-1 (Fixed Rate Bonds) and Southern Transmission System Renewal Project, Revenue Bonds, 2025-2 (Fixed Tender Bonds – Term Rate Mode), under the section entitled "DEVELOPMENTS IN THE CALIFORNIA ENERGY MARKETS." Such Official Statement is on file with the Municipal Securities Rulemaking Board and is available to the public.

The Disclosure Resolution provides, in part, that under no circumstances shall any person or entity be entitled to recover monetary damages in the event the Authority fails to comply with the Disclosure Resolution. The Disclosure Resolution further provides that in the event of any such failure, only certain remedies may be available to Owners or Beneficial Owners. For a description of such remedies, see section 11 of the Disclosure Resolution which is set forth in Appendix F to the Official Statement.

THE CITY OF ANAHEIM

The following is information concerning the City of Anaheim ("Anaheim" or, in this section, the "City"), its Public Utilities Department ("Anaheim Public Utilities" or "APU") and such APU's electric utility (the "Anaheim Electric System" or the "Electric System"), prepared by Anaheim for inclusion herein. This information does not purport to cover all aspects of the business, operations and financial position of the Anaheim Electric System.

Organization

The City of Anaheim is a chartered city of the State of California. Under the provisions of the California Constitution, the Charter of the City of Anaheim (the "Charter") and Title 10 of the Municipal Code of the City, the City owns and operates both the Electric System and a water system (the "Water System") for the citizens of the City. APU exercises jurisdiction over both the Electric System and the Water System and is under the supervision of the Public Utilities General Manager (the "General Manager"). The General Manager supervises the design, construction, maintenance and operation of both the Electric System and the Water System. The Finance Director/City Treasurer oversees the accounting and administration of the financial affairs of the City. The Anaheim City Council (the "City Council") appoints the City Manager, who provides direction to the General Manager and Finance Director/City Treasurer.

The Electric System and the Water System provide services to virtually all residential, commercial, and industrial customers within City limits. The funds and accounts of the Electric System and the Water System are held separately, and the funds and accounts of one system are not pledged to the other system's obligations.

Management of Anaheim Public Utilities

The following are biographical summaries of the executive management team of APU with responsibility for the Electric System:

Dukku Lee, Public Utilities General Manager, has served Anaheim Public Utilities since November 1999 and was appointed as its General Manager in November 2013. He has full management responsibility to plan, direct, and manage APU's day-to-day activities and operations. Mr. Lee began his career in the utility industry in 1993. Prior to his appointment as General Manager, Mr. Lee held the position of Assistant General Manager–Electric Services with responsibility for managing the engineering, construction, operation and maintenance of the utility generation, transmission, and distribution system. Mr. Lee previously worked for Southern California Edison ("Edison") and Paragon Consulting Services. Mr. Lee holds a Bachelor of Science degree in Electrical Engineering from California State Polytechnic University, Pomona and a Master of Science degree in Engineering Management from California State University, Long Beach and is a registered Professional Engineer in the State of California. Mr. Lee is on the Board of Directors of the Southern California Public Power Authority ("SCPPA") and the Board of Governors of the California Municipal Utilities Association ("CMUA").

Brian Beelner, Assistant General Manager–Finance & Energy Resources, has served Anaheim Public Utilities since 2005. He is responsible for multiple aspects of APU including accounting, budget development, financial planning, rate design, long-term forecasting, debt administration, warehousing and supply chain, power supply, and information technology. Prior to joining the City, Mr. Beelner worked for Gursey, Schneider & Co., LLP as a municipal utility accounting and finance consultant. Mr. Beelner graduated from the University of California, Riverside with a Bachelor of Arts degree in Business Economics and currently holds an active Certified Public Accountant license in the State of California. He is a member of the SCPPA Finance Committee and an alternate member of SCPPA's Board of Directors, a member of the Coordinating Committee for the Intermountain Power Project ("IPP"), and a member of the San Onofre Nuclear Generating Station Decommissioning Executive Committee.

Janet Lonneker, Assistant General Manager–Electric Services, joined Anaheim Public Utilities in May 2014, and is responsible for directing, managing, supervising, and coordinating the activities and operations of the Electric Services Division, including electrical engineering, electric operations, system planning, substations, and power generation. Ms. Lonneker has over 25 years of electric utility industry experience, most recently before joining Anaheim as a Customer Solutions Manager for San Diego Gas and Electric ("SDG&E") where she worked within the Smart Grid Division. Prior to her employment at SDG&E, she was General Manager for the City of Forest Grove's Department of Light and Power for six years, where she was responsible for leadership, management, and oversight of all divisions of the utility. Ms. Lonneker holds a Bachelor of Science degree and a Master of Science degree in Electrical Engineering from the University of the Pacific and the University of Southern California, respectively.

Janis Lehman, Assistant General Manager–Administration & Risk Services, has been with Anaheim Public Utilities since 1990. She currently leads the Administration and Risk Services Division which is responsible for enterprise risk management, environmental and regulatory compliance, safety services, legislative and regulatory affairs, and customer service including credit collections and billing. She has experience in all key aspects of the water and electric utility industry. She started her career at APU managing transmission line and power generation projects, as well as developing water programs. Her career path has included working as a hazardous materials design specialist for water and soil projects, a first responder on hazardous materials emergency response teams, and as an engineer at Bechtel Engineering before coming to APU. She has taught several courses on regulatory compliance through California State University. Ms. Lehman currently serves as an alternate on the CMUA Board of Governors. She is a member and past chair of the CMUA Legislative Committee and the Regulatory committee. She is also a member and past chair of the SCPPA Risk Management Committee, a member of the Credit Working Group of the California Independent System Operator Corporation ("CAISO"), and has testified as an expert witness at the California Public Utilities Commission ("CPUC"). Ms. Lehman has a Bachelor of Science degree in Geophysics from University of California, Riverside, and a Master of Business Administration degree from the University of Southern California.

Public Utilities Board

The City Council, by Ordinance No. 3557 approved July 6, 1976, established a Public Utilities Board (the "Public Utilities Board" or the "Board") with the power and duty to make recommendations to the City Council for consideration by the City Council in its determinations concerning (i) the operation and conduct of the Electric System and the Water System, (ii) the establishment of rules and regulations and rates for the operation of the Electric System and the Water System, (iii) the duties and qualifications of the General Manager and other APU employees, (iv) the acquisition, construction, improvement, extension, enlargement, diminution or curtailment of all or any part of the Electric System and the Water System, (v) APU's annual budget, and (vi) financing, including the issuance of bonds for the Electric System and the Water System. On June 3, 2014, City voters approved Measure C which, among other things, added Section 909 to the Charter specifying the powers and duties of the seven-member Public Utilities Board. The Board may also exercise such other powers and duties as may be prescribed by ordinance not inconsistent with the Charter.

The Board consists of seven members, none of whom may hold any paid office or employment in the City government. The members of the Board are appointed by the City Council and may be removed by a majority vote of the City Council. Board members serve four-year overlapping terms and are limited to serving two consecutive four-year terms.

The present members of the Board and their terms of appointment are:

John Seymour, Chairperson, term expires December 31, 2026. Mr. Seymour joined the Board in April 2017, and was reappointed in January 2023. He is a retired telecommunications executive with a bachelor's degree from Whittier College in Economics and Business Administration with an emphasis in Accounting. Mr. Seymour previously served on the City's Planning Commission (2010-2017), and is a former member and chair of the Public Utilities Board's Underground Conversion Subcommittee. He served on the board for the Anaheim Regional Medical Center for over twenty years, and served as a board member for Memorial Health Services.

Anh Pham, M.Ed., Vice Chairperson, term expires December 31, 2025. Mr. Pham joined the Board in February 2022. He is a civil rights administrator for the University of California, Irvine, and prior to that, spent a decade working for the University of California, Riverside. He earned a Bachelor of Arts degree in Public Policy as well as a Master of Education in Higher Education Administration and Policy from the University of California, Riverside.

Albert McMenamin, term expires December 31, 2026. Mr. McMenamin joined the Board in January 2023. He began his career with the City. During his 37-year career, he worked in the water services division and held the positions of Equipment Operator, Maintenance Pipefitter and Senior Water Utility Inspector. Mr. McMenamin has also worked part time with the Los Angeles Angels since 2001.

Mitch Lee, term expires December 31, 2028. Mr. Lee joined the Board in August 2021. He retired from the Boeing Company after 20 years as a Deputy Project Manager. Previously, Mr. Lee worked at Northrop Grumman Corporation for 13 years as an engineer. Throughout his career, he worked on several U.S. Government, international and commercial programs. Currently, he is a consultant and an advisory board member for Theory Seventy Three Corp.

Talab Ibrahim, term expires December 31, 2028. Mr. Ibrahim joined the Board in February 2023. He attended California State University, Fullerton where he earned his Bachelor of Science degree in Civil Engineering. In college, he joined the American Society of Civil Engineers and Institute of Transportation Engineers. Currently, he manages a family business in Anaheim and serves as a property manager at family-owned properties in Orange County.

Ivan Castillo, term expires in December 31, 2028. Mr. Castillo joined the Board in August 2025. He earned his bachelor's degree in Political Science from Loyola Marymount University in 2004. Mr. Castillo spent 17 years with the Irvine Company. He currently serves as a Business Advisor at Insperity, supporting small and mid-sized businesses across Southern California.

Hon. Shashi H. Kewalramani (Ret.), term expires December 31, 2026. Mr. Kewalramani joined the Board in November 2025. He currently serves as a mediator and arbitrator with JAMS, a national organization providing private dispute-resolution services, following a distinguished career on the federal bench and in public service. He previously served as a U.S. Magistrate Judge for the Central District of California and, before that, as an Assistant U.S. Attorney in both the Northern and Central Districts of California, where he handled complex cybersecurity, fraud, and intellectual-property matters. Mr. Kewalramani also possesses private-sector experience representing clients in intellectual-property and commercial litigation. He earned his J.D. from Baylor University School of Law and a B.S. in Aerospace Engineering from the University of Texas at Austin.

History of the Electric System

The Anaheim Electric System was established in 1894. The original City-owned generating plant was placed in service in 1895 and consisted of a steam-driven generator of 500 lights capacity. By 1896, the maximum capacity of the original generating plant had been reached and City voters authorized bonds for the combined rebuilding of both the electric light plant and the City's water system. In 1916, the City negotiated to purchase all of its power from Edison. In the years that followed, the City challenged rate increases and other measures undertaken by Edison, ultimately resulting in a settlement between Edison and the City in 1972 that permitted the City to take advantage of lower-cost power resources.

From 1976 to 1983, the City continued to purchase a majority of its power supply from Edison. During that span, the City also purchased energy from Nevada Power and other utilities in the western United States. Also during this period, the City voters supported a series of revenue bond issues and other financing options to allow the utility to participate in a power diversification process. Included in this process was the City joining SCPPA, a joint exercise of powers authority created for planning, financing, developing, acquiring, constructing, improving, operating, and maintaining electric generating and transmission projects for participation by some or all of its members.

By the late 1980s and early 1990s, the City received power from a variety of sources, including contractual arrangements for capacity and energy, a 40 megawatts ("MW") share of power generated at the Hoover Dam, and ownership interests in projects such as the San Juan Generating Station ("SJGS" or "San Juan") in New Mexico. As a result of the City's efforts to diversify its electric generating power resources, the City purchased less than 2% of its energy from Edison in 1997, and by 2002, the City did not purchase any of its energy requirements from Edison.

During this period, the City also began developing a project to remove overhead power lines and poles on major public roads. The City Council approved a recommendation from the Public Utilities Board to establish an underground utility conversion program in 1991, which aimed to improve the Electric System's reliability by hardening the system against outages caused by weather, metallic balloons, and vehicle accidents, while also beautifying the City's streets and enhancing property values.

Today, the City's power is produced at generating plants in or near the City and at locations across the western United States. The Electric System serves the entire area of the City, covering approximately 50 square miles of the northern portion of Orange County, which is about 28 miles southeast of downtown Los Angeles, and about 90 miles north of San Diego. The City lies on a coastal plain which is bordered by the Pacific Ocean to the west and the Santa Ana Mountains to the east. For the Fiscal Year ended June 30, 2025, the Electric System served an average of 125,065 customers and sold approximately 2,786,879 megawatt-hours ("MWh") of energy.

The table below sets forth historical Electric System resources:

TABLE 1
HISTORICAL RESOURCES
CAPACITY (MW)

	Fiscal Year Ended June 30				
	2025	**2024**	**2023**	**2022**	**2021**
Non-City Owned Resources					
Hoover	40	40	40	40	40
IPP	236	236	236	236	236
Magnolia	118	118	118	118	118
Canyon Power Project[(1)]	200	200	200	200	200
Non-City Owned Renewable Resources					
Ormat Technologies	-	-	-	8	8
PPM Energy	30	32	32	32	32
Brea Power Partners	27	27	27	27	27
Cyrq Energy, Inc. subsidiary[(2)]	7	7	7	7	7
San Gorgonio Farm	31	31	31	31	31
Haypress	13	-	-	-	-
MWD Hydro[(3)]	-	10	10	10	10
Bowerman Power	20	20	20	20	20
Westlands (Westside Solar, LLC)	2	2	2	2	2
Loyalton (ARP Loyalton Cogen, LLC)[(4)]	-	-	-	1	1
Desert Harvest II	36	36	36	36	36
Total Resources	760	759	759	768	768

(1) See " - Power Supply Resources - Non-City Owned Resources – Canyon Power Project" below.
(2) Cyrq Energy, Inc.'s former name was Raser Technologies.
(3) Through SCPPA, the City contracted with the Metropolitan Water District of Southern California (MWD) for a 56.5% share – approximately 9.7 MW – from four small hydroelectric plants located in the Los Angeles Basin between November 1, 2008, through December 31, 2023.
(4) The City last received power from the Loyalton Project in calendar year 2020; the 1 MW shown under Fiscal Years 2022 and 2021 represents the project nameplate capacity before the City terminated its purchase power agreement on April 19, 2023.

Source: Anaheim.

The City's power supply is derived from a variety of electric generating resources in order to provide lower rates and reliable service to its customers. The City supports environmentally sound energy generation, and continues to increase renewable resources as part of its overall power portfolio. See "Power Supply Resources – Renewable Energy Resources" below.

Principal Facilities

The Electric System includes generation, transmission and distribution facilities. As of June 30, 2025, the Electric System's principal facilities consisted of approximately 1,263 circuit miles of transmission and distribution lines, and 14 distribution substations.

The City also purchases power and transmission service from other entities. See "Power Supply Resources – Non-City Owned Resources" below.

The following table sets forth information relating to the assets, production capacity, and production costs, per category of resource, of the Electric System for the five fiscal years shown:

TABLE 2
ELECTRIC SYSTEM STATISTICS
($000)

	Fiscal Year Ended June 30,				
	2025	**2024**	**2023**	**2022**	**2021**
Investment in Utility Plants:					
Production	$ 46,103	$ 46,103	$ 46,103	$ 46,103	$ 46,103
Transmission	122,526	113,877	113,886	113,823	109,011
Distribution	1,348,412	1,300,291	1,292,161	1,262,770	1,194,849
General	170,933	165,686	163,076	161,162	154,792
Right to use asset - Land	3,901	3,901	3,200	3,200	-
Right to use asset - Equipment	334	-	-	-	-
Subscription base assets (SBITA)	2,675	658	658	658	-
Gross utility plant	1,694,884	1,630,516	1,619,084	1,587,716	1,504,755
Less–accumulated depreciation	(833,535)	(785,302)	(737,607)	(693,299)	(649,346)
Net plant in service	861,349	845,214	881,477	894,417	855,409
Land	34,243	34,243	34,243	34,243	34,243
Construction work in progress	250,105	190,470	134,139	99,346	123,368
Total utility plant	$1,145,697	$1,069,927	$1,049,859	$1,028,006	$1,013,020
Production Costs					
Owned Generation(1)	$ -	$ -	$ 265	$ 399	$ 68
Purchased Power(2)	206,821	196,788	232,720	208,152	192,618
Total Production Costs	$ 206,821	$ 196,788	$ 232,985	$ 208,551	$ 192,686
Transmission-69 kV Circuit Miles	89	89	89	89	89
Distribution Overhead Circuit Miles	383	384	389	389	391
Underground Circuit Miles	791	783	769	769	764
Transformer Capacity (in kVA)					
220 kV to 69 kV	1,808,000	1,808,000	1,808,000	1,808,000	1,808,000
69 kV to 12 kV	1,325,800	1,325,800	1,325,800	1,325,800	1,325,800
12 kV to Customer	1,887,097	1,832,239	1,832,239	1,832,239	1,910,561

(1) Cost information includes debt service on facilities during the fiscal period. See " - Power Supply Resources" for discussion of reduction in City-owned generation.
(2) Excludes transmission costs and gas sold.
Source: Anaheim.

In the Fiscal Year ended June 30, 2025, the City purchased approximately 3,059 gigawatt-hours ("GWh") of electricity. Combined customer electric requirements created the historic distribution system peak demand of 593 MW on July 24, 2006. The following table sets forth the total Electric System GWh of energy purchased and electric distribution system peak demand during the five fiscal years shown:

TABLE 3
TOTAL GIGAWATT HOURS (GWh) GENERATED
AND PURCHASED AND PEAK DEMAND (MW)

	Fiscal Year Ended June 30,				
	2025	**2024**	**2023**	**2022**	**2021**
Firm Purchases:					
Intermountain Power Project	927	592	761	805	1,063
Hoover Uprating Project	33	31	30	38	41
Magnolia Power Project	489	564	581	553	418
Canyon Power Project[(1)]	54	90	127	99	99
Renewable Resources[(2)]	961	735	666	732	696
Subtotal	2,464	2,012	2,165	2,227	2,317
Non-Firm Purchases:	595	610	557	554	429
System Total Energy Generated and Purchased, GWh[(3)]	3,059	2,622	2,722	2,780	2,746
Distribution System Peak Demand, MW	579	500	566	487	559

(1) Canyon Power Project is a peaking unit, and total generation each year varies based on demand and market prices.
(2) Renewable resources vary by year, but meet the RPS requirements, sometimes supplemented with renewable energy credits ("RECs").
(3) Includes energy purchased that was ultimately sold in the wholesale market. Also includes RECs purchased. Totals may not add due to rounding.
Source: Anaheim.

Power Supply Resources

The City's electric resources currently consist of power from firm purchases with entitlements in the IPP of the Intermountain Power Agency ("IPA"), in the Hoover Uprating Project of the federal government, and in SCPPA's Magnolia Power Project and Canyon Power Project (in which the City has an entitlement to 100% of the capacity and energy thereof), and firm power purchases and non-firm energy purchases from other utilities, which can include a number of renewable energy resources. Each of these resources is more fully described below. The City's resources previously included the City-owned Kraemer Combustion Turbine ("CT") Power Plant (the "Kraemer CT Plant") and ownership interests in the SJGS and the San Onofre Nuclear Generating Station ("SONGS"). The City has retired the Kraemer CT Plant from operation and divested its ownership interests in the latter two resources but retains certain environmental and decommissioning obligations, which are described in more detail below.

Previous City Resources

Kraemer CT Plant. The City owned 100% of the Kraemer CT Plant, a natural gas-fired combustion turbine plant located in the northeast part of the City, adjacent to the City's Dowling Substation. The Kraemer CT Plant began operation in May 1991 and ceased operations in March 2019 due to required turbine repairs. The City permanently ceased operation of the Kraemer CT Plant as of December 31, 2019 because the repair of the turbine was impractical and cost prohibitive due to the scarcity of repair parts for the turbine's model. Furthermore, there appeared to be only one vendor who could service and repair the turbine and that vendor was expected to cease depot repair of this turbine model on or about December 31, 2022. Demolition of the plant was completed in June 2025, at an approximate cost of $400,000.

San Juan Generating Station Unit 4. In April 1991, the City purchased a 10.04% (50 MW) undivided ownership interest in Unit 4 of the San Juan Generating Station ("SJGS"), located in San Juan County in northwestern New Mexico, near Farmington, New Mexico. The SJGS is a four-unit coal-fired steam electric generating plant. Unit 4 had a rated net generating capability of 507 MW (as of December 31, 2017). Public Service Company of New Mexico constructed Unit 4 and manages its operations. The City purchased its 50 MW share in Unit 4 for a price of $55 million, which the City financed through revenue bonds of the Electric System. The City ceased to have an ownership interest in the SJGS effective December 31, 2017; approximately 182 GWh of energy was provided to the City from its San Juan Unit 4 ownership interest in the Fiscal Year ended June 30, 2018, prior to such date.

In connection with divestiture by the City and other participants from the plant and a restructuring thereof, the City (along with the other exiting participants) retains certain liabilities for its respective share of the costs of the SJGS decommissioning and pre-exit date mine reclamation costs. The City's proportionate share of decommissioning costs is 2.7%, following the retirement of SJGS from service in October 2022. The total estimated cost to complete decommissioning is $70 million, with the City's share estimated at $1.9 million. Decommissioning activities are in progress with an estimated completion in 2026. However, certain ponds and pumps will remain operational to support reclamation activities and monitoring through 2040.

The City's share of reclamation is 3.1% of all pre-2017 year-end mining activities. The total estimated cost to complete reclamation, including both pre- and post-2017 mining activities, is approximately $148 million, with the City's share estimated at approximately $4.5 million. Reclamation is anticipated to be completed by 2040.

The City has fulfilled its required contributions to the mine reclamation trust funds and has funded the SJGS decommissioning trust fund for plant decommissioning activities. Annual contributions to the decommissioning trust fund will continue through the completion of decommissioning, with funding levels aligned to the work scheduled for each year.

San Onofre Nuclear Generating Station. Until 2007, the City's interest in the San Onofre Nuclear Generating Station ("SONGS") was the most significant City-owned generation resource in its portfolio. Under agreements with Edison, the City acquired a 3.16% ownership interest in SONGS Units 2 and 3, totaling 1,070 MW and 1,080 MW of capacity, respectively. Maintenance and operation of SONGS remained the responsibility of Edison under an operating agreement with the City (the "SONGS Operating Agreement") and other agreements with various participants. As a result of the transfer of the City's ownership interest in SONGS to Edison at the end of 2006, none of the City's firm power supply has been obtained from SONGS since 2007.

After a number of developments at the plant and numerous meetings in the public sphere and with the United States Nuclear Regulatory Commission (the "NRC"), Edison announced on June 7, 2013 its intention to permanently cease power generation operations and shut down Units 2 and 3. On August 19, 2021, Edison submitted a decommissioning cost analysis study to the NRC. Based upon Edison's most recent decommissioning cost study, amounts previously funded by the City and held in trust are expected to fully fund the City's share of SONGS decommissioning costs; however, until the actual total overall decommissioning costs are finally determined, no assurance can be given that additional contributions will not be required by the City. A decommissioning general contractor was selected in December 2016 to decontaminate and dismantle the facility. The decommissioning work is scheduled to be completed by the end of 2028, and full site restoration is expected to be completed by the end of 2051.

Non-City Owned Resources

The City purchases power from other sources pursuant to contracts. These contracts provide generally for the City to pay costs associated with the firm purchase of power (fixed costs) as well as operations, maintenance and administrative expense (variable costs). Information regarding the total cost of power purchased from these facilities is set forth in the table captioned "Electric System Statistics." With respect to each of the facilities discussed herein other than the Canyon Power Project, the City is one of several purchasers of such power and does not control the operations or management of such facility.

Intermountain Power Project. IPA constructed and placed into operation the IPP. The IPP consists of: (a) a two-unit, coal-fired, steam-electric generating plant with a net rating of 1,800 MW (the "Intermountain Generating Station") and a switchyard (the "Switchyard"), located near Lynndyl, in Millard County, Utah; (b) a ±500-kV direct current ("DC") transmission line approximately 490 miles in length from and including the Intermountain Converter Station (an alternating current ("AC")/DC converter station adjacent to the Switchyard) to and including a corresponding converter station at Adelanto, California (collectively, the "Southern Transmission System" or "STS") (see "Transmission Resources – Southern Transmission System" below); (c) two 50-mile, 345-kV AC transmission lines from the Switchyard to the Mona Switchyard in the vicinity of Mona, Utah, and a 144-mile, 230-kV AC transmission line from the Switchyard to the Gonder Switchyard near Ely, Nevada (collectively, the "Northern Transmission System" or "NTS"); (d) a microwave communications system; (e) a rail car service center located in Springville, in Utah County, Utah (the "Railcar Service Center"); and (f) certain water rights and coal supplies. Such water rights and coal supplies, together with the Intermountain Generating Station, the Switchyard and the Railcar Service Center, are referred to herein collectively as the "Generation Station."

Thirty-five utilities (collectively, the "IPP Purchasers") purchase the Generation Station's output. The IPP Purchasers include the City, and the California cities of Los Angeles, Riverside, Burbank, Glendale and Pasadena (the "IPP California Participants"); 23 members of IPA (collectively, the "Utah Municipal Purchasers"); and six rural electric cooperatives serving loads in the States of Utah, Arizona, Colorado, Nevada and Wyoming (collectively, the "Cooperative Purchasers"). Pursuant to a construction management and operation agreement between IPA and the Los Angeles Department of Water and Power ("LADWP"), LADWP acts as project manager and operating agent of the IPP, responsible for, among other things, administering, operating and maintaining the IPP. The facilities of the IPP have been in commercial operation since May 1987.

The City contracted with IPA to purchase a 236 MW (13.2259%) entitlement in the capacity of the IPP plant through mid-2027. This contract obligates the City to pay in proportion to its entitlement share the costs of producing and delivering electricity (including debt service and other fixed expenses) as a cost of purchased capacity, regardless of the amount of energy scheduled to the City.

In the Fiscal Year ended June 30, 2024, the Intermountain Generating Station operated at a net plant capacity factor of approximately 26.22%. In the Fiscal Year ended June 30, 2025, the Intermountain Generating Station operated at a net plant capacity factor of approximately 60%.

IPA possesses coal supply agreements to fulfill the supply requirement of approximately 900,000 tons in calendar year 2025. The coal was purchased under a portfolio of fixed-price contracts that lasted through August 2025. As a result of the decline in coal-fired generation around the nation, the coal market has constricted, especially in Utah, which has dramatically reduced supply in the region near IPA. The recent cost of coal delivered to the Intermountain Generating Station is similar to current market prices for the region. However, IPA expects the costs of any incremental coal purchases will increase due to the scarcity of coal in the Western United States and suppliers looking to other, longer-term buyers.

Transportation of coal to the Intermountain Generating Station is provided primarily by rail under agreements between IPA and the Union Pacific Railroad Company. The coal is transported primarily in IPA--owned railcars. Coal is also transported to IPP, to some extent, in commercial trucks. Both rail service and trucking services have suffered greatly due to a lack of human resources. Neither network is capable of supporting industrial demand, and IPA, like all coal-fired utilities in the United States, has seen large systemic failures in the transportation system.

IPP coal operation was shut down on November 26, 2025.

LADWP, as operator of the facility, has operational flexibility with respect to its use of IPP; however, the supply chain issues referenced above and the transition period to IPP's natural gas units will limit coal operations of IPP and may constrain LADWP's ability to utilize such resource until the repowering project is operational.

The Southern Transmission System provides transmission of IPP's output to the City and the other IPP California Participants. The City and SCPPA have entered into a transmission service contract to provide for transmission of the City's entitlement between the Generation Station and Adelanto. See "– Transmission Resources – Southern Transmission System" below. Transmission service from Adelanto to the City is provided under transmission service agreements with LADWP and transmission service under the CAISO tariff.

The current power purchase agreements with IPA are in effect until mid-2027. IPP's operations are affected by California Senate Bill 1368, which became effective in January 2007, and prohibits any investment in baseload generation that does not meet specific emissions performance standards, subject to certain exceptions. In light of that restriction and as a result of strategic discussions concerning the existing contracts' expiration, IPA developed a plan to convert the coal-fired facility to a combined-cycle natural gas-fired resource. In order to facilitate the continued participation of the IPP California Participants, the IPA Board and the IPP Participants, including the City, executed individual Second Amendatory Power Sales Contracts that allow the plant to replace the coal units with combined-cycle natural gas units before 2027. The City will exit IPP upon the expiration of the current power purchase agreement in mid-2027, and does not expect to incur material costs associated with the construction of the proposed natural gas-fired units beyond 2027. Pursuant to the Second Amendatory Power Sales Contract, to the extent the existing coal units are replaced with natural gas-fired units as proposed, the City will not be responsible for future decommissioning costs associated with the IPP when the power purchase agreement expires in mid-2027. In the event that financing of the proposed natural gas-fired renewal project is not undertaken as currently proposed, the allocation of decommissioning costs to IPP Purchasers (including the City) may vary depending on the date the IPP is ultimately retired from service, what alternative project or use, if any, is instituted at the site, the level and type of remediation and/or restoration undertaken or required, and the financing options and amortization schedule for decommissioning costs.

The Utah Legislature enacted Utah Senate Bill 161 ("Utah S.B. 161") in its 2024 General Session, which became effective on May 1, 2024. The reported purpose of Utah S.B. 161 was to induce IPA to amend IPA's environmental permits to provide for the operation of at least one of the IPP coal-fired units after July 1, 2025, the date by which IPA has committed to cease operation of the IPP coal units permanently. Utah S.B. 161 also required IPA to grant an option to the State of Utah for the purchase of at least one of the IPP coal-fired units with such option to be effective for two years starting on July 2, 2025. Following the enactment of Utah S.B. 161, the governor of Utah called a special session of the Utah Legislature resulting in the enactment of Utah House Bill 3004 ("Utah H.B. 3004"), which became effective on June 21, 2024. Utah H.B. 3004 repealed the provisions of Utah S.B. 161 relating to IPA amending its environmental permits. IPA continues, however, to be obligated to provide the purchase option to the State with respect to one of the IPP coal-fired units. Utah H.B. 3004 also directs a state agency, the Decommissioned Asset Disposition Authority (the "Utah Disposition Authority"), to submit an application to amend IPA's air permit to allow for a coal unit to operate after July 1, 2025. Utah H.B. 3004 also directs environmental regulators in the State of Utah to determine whether such an application would be granted if submitted by IPA. The Utah Disposition Authority has also been directed to determine the regulatory and commercial feasibility of operating an IPP coal unit after July 1, 2025, and to conduct a process for soliciting bids from qualified purchasers for the coal unit.

Prior to the enactment of H.B. 3004, IPA stated that Utah S.B. 161 purported to create obligations for IPA that are inconsistent with IPA's obligations under federal regulations and the IPP construction and operating permits issued under federal law; and that if IPA complied with Utah S.B. 161, as originally enacted, IPA may be subject to enforcement actions that could result in IPA being required to cease operation of the IPP coal units prior to the scheduled commercial operation date of the IPP repowering project and that may interfere with the construction and operation of the IPP repowering project. In public testimony with respect to Utah H.B. 3004, IPA management stated that the new bill made some important adjustments to the legislation and moved things in the right direction. IPA has indicated that it is still working to determine the impact of Utah S.B. 161, as modified by Utah H.B. 3004, and to identify the appropriate course of action in response to the recent enactments.

During its 2025 General Session, the Utah Legislature enacted Utah House Bill 70 ("Utah H.B. 70"). The bill became effective on March 24, 2025. The bill requires IPA to maintain, indefinitely (i) power to station service for both of the coal units, (ii) an ongoing connection of one of its coal units to the IPP Switchyard, and (iii) interconnection and switchyard facilities that will allow the remaining coal unit to be interconnected with the IPP Switchyard without the need for a new interconnection request. Utah H.B. 70 also creates the Utah Energy Council for, among other purposes, the purposes of taking title to one or both of the coal units and assuming operational responsibility for each coal unit it acquires from IPA. Utah H.B. 70 also repeals the provisions of the Utah Code establishing the Utah Disposition Authority (effectively dissolving the Utah Disposition Authority) and the provisions specifying the functions that the Utah Disposition Authority was to have performed.

IPA is working with engineering personnel to reconfigure the proposed connections of synchronous condensers to the IPP Switchyard (connecting three synchronous condensers to the IPP Switchyard at one point of interconnection as opposed to two synchronous condensers at one point of interconnection and one synchronous condenser at another). IPA is constructing the synchronous condenser facilities to provide sufficient spinning mass to allow for operation of the natural gas units as designed and to maintain the rating of IPA's transmission facilities. IPA has indicated that it believes that it will be able to comply with the requirements of Utah H.B. 70, though such requirements will result in additional costs to IPA and will diminish the redundancy that would have resulted from having two points of interconnection for the synchronous condensers to the IPP Switchyard. IPA is continuing to evaluate the future impacts of complying with Utah H.B. 70.

The City cannot predict the ultimate impacts of the new legislation on the operation of IPP or on the construction and operation of the IPP repowering project. With respect to the status of the repowering project, the new generation facilities were previously anticipated to enter service in summer 2025. However, the repowering units were delayed until fall. Unit 3 entered commercial operation on October 10, 2025. Unit 4 entered commercial operation on December 9, 2025.

Hoover Uprating Project. The Hoover Uprating Project consists primarily of the uprating of the 17 generating units at Hoover Dam's hydroelectric power plant, located approximately 25 miles from Las Vegas, Nevada. The City's entitlement in the Hoover Uprating Project was approximately 40 MW. A portion of the City's Hoover entitlement became available in June 1987 and the full entitlement became available in June 1993. The Hoover Uprating Project was substantially completed on September 30, 1995. The City originally assigned its entitlement to capacity and energy of the Hoover Uprating Project to SCPPA (in return for which SCPPA financed the advancement of funds to the United States Bureau of Reclamation for costs of the Hoover Uprating Project) and executed a power sales contract with SCPPA under which the City agreed to make monthly payments on a "take-or-pay" basis for its share of SCPPA's proportionate share of Hoover capacity and allocated energy. These agreements expired on September 30, 2017.

The City renegotiated and executed replacement agreements directly with the Western Area Power Administration ("Western") and the United States Bureau of Reclamation, which became effective on October 1, 2017 and extend until September 30, 2067. The City's entitlement under the new agreements remains at approximately 40 MW. Western delivers the City's entitlement at the Mead Substation.

Magnolia Power Project. The Magnolia Power Project is a natural gas-fired, combined cycle electric generating unit with a nominally rated net capacity of 242 MW and auxiliary facilities located in Burbank, California. The Magnolia Power Project is owned by SCPPA and is operated by the City of Burbank electric utility. The Magnolia Power Project was placed in service in September 2005 and operates in a base-load mode (8,000 hours per year or more) with staffing on a 24-hour basis. The City acquired a 38% (92 MW base capacity and 26 MW peaking capacity) entitlement in the project through a long-term power purchase agreement with SCPPA. Under its power sales agreement with SCPPA, the City is obligated to pay, on a "take-or-pay" basis, its share of the costs of the Magnolia Power Project (including operating and maintenance costs and the costs of debt service on bonds issued by SCPPA for the project) as an operating expense of the Electric System.

Canyon Power Project. The Canyon Power Project consists of a simple cycle, natural gas-fired power generating plant comprised of four General Electric LM 6000PC Sprint combustion turbines, with a combined nominally rated net peaking capacity of 200 MW, and auxiliary facilities located on approximately 10 acres of land within an industrial area of the City. The Project is owned by SCPPA and operated and maintained by the City. The Canyon Power Project was constructed for the primary purpose of providing the City with firm capacity and energy to meet its current and future capacity and energy requirements and to satisfy certain ancillary services requirements. The Canyon Power Project achieved full commercial operation in 2011. The City entered into a power sales agreement with SCPPA pursuant to which the City acquired an entitlement to 100% of the capacity and energy of the Canyon Power Project and is obligated to pay, on a "take-or-pay" basis, 100% of the costs of the project, including all operating and maintenance costs and the costs of debt service on bonds issued by SCPPA in connection with the Canyon Power Project as an operating expense of the Electric System.

The Canyon Power Project is subject to the New Source Review ("NSR") air quality permitting program promulgated by the Southern California Air Quality Management District ("SCAQMD"), the agency responsible for developing and enforcing air quality requirements in the South Coast Air Basin (the "Basin"), which includes Los Angeles, Riverside, San Bernardino and Orange Counties. The SCAQMD's NSR program is required to comply with certain provisions and requirements established pursuant to federal and State law, including the federal Clean Air Act. The federal Clean Air Act sets standards for different types of air pollutants and allows states to create plans to address pollution in areas with unclean air. These programs may include emission offset trading programs that require new sources to obtain emission reduction credits ("ERCs") for every pound of new pollution that they propose to emit.

On June 21, 2024, Canyon Power Plant Unit 1 experienced a significant mechanical failure while in full operation. The unit suffered a compressor stall when one of the compressor blades broke off from the rotor, damaging all blades within the compressor. The unit is currently undergoing repairs at TransCanada Turbines in Canada. Because of industrywide shortages of gas turbine parts, the City anticipates completing repairs by early 2026. The cost of such repairs is estimated at approximately $8 million, reflecting replacement parts, shipping, labor costs for tear-down, and inspection and analysis. Factoring in lost wholesale revenue but reduced fuel expenses, the City estimates a $2.26 million dollar reduction in net revenue.

The June 2024 incident appears related to a known issue with GE turbines. GE issued a service bulletin recommending the replacement of Stage 3 through Stage 5 blades after 1,500 starts. However, Canyon Unit 1 experienced failure at approximately 1,000 starts, indicating an immediate need to implement this service bulletin across all units. Although all other units are below the critical threshold for starts, the City performed proactive maintenance to mitigate the risk of similar failures—ordering three sets of replacement blades and installing them on Units 2 and 4 in January 2025, at a total cost of approximately

$242,000. The City will place the third set of blades into storage for future scheduled maintenance on the remaining units.

On December 12, 2024, the City discovered a cracked turbine blade on Canyon Power Plant Unit 3 during a bi-annual borescope inspection. Following the inspection, the City placed this unit out of service for repair. The cost to repair the unit was approximately $3.1 million, and reduced net revenue by approximately $157,765, reflecting lost wholesale revenue but reduced fuel expenditures. Canyon Unit 3 repairs were completed in August 2025, and the unit returned to service on August 27, 2025.

Additionally, the failure of Canyon Unit 1 and Unit 3 impacts APU's generation capacity and poses a resource adequacy constraint. To address resource adequacy, APU has procured 227 MW due to the Unit 1 outage and anticipates procuring an additional 194 MW for Unit 3, with the average cost of total procurement estimated at $33/kW-month to meet resource adequacy requirements through the duration of the outages.

Participation of Other Parties in Generation Resources

Each of the projects (other than the Canyon Power Project and the Hoover Uprating Project described above under "– Non-City Owned Resources") is subject to the other parties involved in those projects meeting their respective payment obligations with respect to such projects. If a party defaults on its payment obligations, then the non-defaulting parties, subject to the utilization of any reserves, may be required to expend additional funds with respect to such project. If a non-defaulting party does step-up to the payment obligation of a defaulting party, the non-defaulting party will ultimately have a right to the capability or output of the defaulting party's share of the project. See also "Indebtedness; Joint Powers Agency Obligations" below.

Renewable Energy Resources

Consistent with State legislation, the City first adopted a Renewables Portfolio Standard ("RPS") on December 16, 2011 that set a target of increasing its purchases of eligible renewable energy resources to 33% within three multi-year compliance periods though 2020. Since the adoption of the City's first RPS, Senate Bill 350, the Clean Energy and Pollution Reduction Act of 2015, signed into law in October 2015, increased the statewide RPS targets to 40% by December 31, 2024, 45% by December 31, 2027, and 50% by December 31, 2030. Senate Bill 100, the 100 Percent Clean Energy Act of 2018, signed into law by the Governor on September 10, 2018, further increased statewide RPS targets by requiring retail electric sellers and local publicly-owned electric utilities, such as the City, to procure a minimum quantity of electricity products from eligible renewable energy resources so that the total kWhs of those products sold to retail end-use customers achieve 44% of retail sales by December 31, 2024, 52% of retail sales by December 31, 2027 and 60% of retail sales by December 31, 2030. Senate Bill 100 established the policy of the State that eligible renewable energy resources and zero-carbon resources supply 100% of retail sales of electricity to California end-use customers by December 31, 2045. The City met all RPS compliance targets for Compliance Period 1 (covering calendar years 2011 through 2013), Compliance Period 2 (covering calendar years 2014 through 2016), and Compliance Period 3 (covering calendar years 2017 through 2020). The City anticipates meeting RPS requirements for Compliance Period 4, covering calendar years 2021 through 2024, and awaits the California Energy Commission's determination of that result.

The City's current renewable energy resources are described below. As a component of the Electric System rates and charges, the City implemented an Environmental Mitigation Adjustment which provides a mechanism for the recovery of the marginal cost differential between the utility's renewable power supply and its traditional carbon-based power supply that are not otherwise recovered in its rates. See "Electric Rates and Charges" below.

PPM Wind Contracts. The City purchased 32 MW of wind generated energy from PPM Energy under two separate contracts. Wind energy typically comes with a 33% load factor, so the PPM Energy contracts effectively represent 12 MW of resources. The first contract provides for delivery of 2 MW of energy 24 hours-a-day at a fixed price of $53.50 per MWh over the 20-year term of the contract, which began July 1, 2004. The second contract provides 30 MW (effectively 10 MW) at a fixed price of $55 per MWh over the 20-year term of the contract, which began July 1, 2005. The City receives energy under this contract over the Northern Transmission System at the Mona interconnection tie in the LADWP control area. The City pays for energy only when the units are operating. The 2 MW contract expired December 31, 2023, but the remaining 30 MW contract remains in place.

Brea Landfill Contracts. The City executed two power purchase agreements with Brea Power Partners, LP to deliver landfill gas renewable energy. The first short-term contract was for 5 MW with a start date of April 1, 2007 (with power received commencing July 9, 2007) from an existing facility at the Olinda Landfill through (i) the commercial operation date of a second unit or (ii) December 31, 2013. The price for energy from the Olinda Landfill project remained at $69.00 per MWh through December 31, 2008 and then increased to $71.00 per MWh on January 1, 2009, with an annual price escalation thereafter of 2% commencing January 1, 2010. In November 2012, a second long-term contract superseding the original contract was executed, which provides for a total of 27 MW from the new unit at the Olinda Landfill project upon commercial operation of the second unit, which occurred in November 2012. The contract for 27 MW expires October 31, 2045. The price is $112.50 per MWh with no escalation over the term of the contract. See " - Future Power Supply; Cost of Power and Non-Firm Power - Clean Energy Project" below.

Raser Geothermal Contract (Cyrq Energy). The City executed a power purchase agreement with a Raser Technologies subsidiary corporation for energy from an 11 MW geothermal project located in central Utah, at an initial cost of $78 per MWh with a 2% annual escalation factor for a 20-year term that expires on September 30, 2033. The energy is delivered to the City over the Northern Transmission System at the Mona interconnection tie in the LADWP control area, at an additional transmission cost of $2.98 per MWh. The project began commercial operation in April 2009. On or about April 29, 2011, Raser Technologies, Inc. and its Affiliated Debtors filed voluntary petitions for relief under the Bankruptcy Code. On August 30, 2011, the Bankruptcy Court confirmed the Third Amended Plan of Raser Technologies, Inc. and its Affiliated Debtors with a Plan effective date of September 9, 2011. Raser Technologies changed its name to Cyrq Energy, Inc. The Bankruptcy Court approved the reorganized subsidiary corporation's assumption of its power purchase agreement with the City. Upon the completion of a generator upgrade on November 1, 2013, an amendment to the power purchase agreement was entered into by the City with the new Cyrq Energy subsidiary to include the Ormat Energy Converter with a nameplate capacity of 14,000 gross kW. The amended agreement provides for up to 11 MW of energy for a 20-year term, expiring in 2033, with an energy cost of $98.50 per MWh and a 2% annual escalation factor, and transmission costs of $3.13 per MWh.

San Gorgonio Wind Contract. The City executed a power purchase agreement with San Gorgonio Farms, Inc. for 31 MW of wind energy from the existing San Gorgonio Farms Wind Farm located in Whitewater, California. This facility reached commercial operation in 1983 and was originally under contract to Edison. The price for power is split between the environmental attributes and energy. Environmental attributes are priced at $38.50 per MWh with no escalation and the energy price equals the revenue paid by the CAISO for delivery of the project's energy less all CAISO charges, fees, debits, costs, penalties, and interest assigned to the project. In April 2023, the City approved an amendment to the agreement with San Gorgonio Farms, Inc. resulting in an updated price of $22 per MWh and an extension to the term through December 31, 2033.

Bowerman Power Landfill Contract. The City executed a power purchase agreement with Bowerman Power, LLC for the purchase of 19.6 MW of energy generated from landfill gas from the Frank R. Bowerman Landfill in Irvine, California. Commercial operations began on April 27, 2016. The term of the agreement is 20 years, expiring on April 30, 2036. The generating facility is expected to produce 154 GWh annually. The annual total cost for the renewable energy and RECs is approximately $13.5 million with a 2.5% escalator during the first 10 years, 1.5% for the next five years, and no escalator thereafter. The initial price (during the first year) under the agreement amounts to $87.40 per MWh less all CAISO charges, fees, debits, costs, penalties, and interest assigned to the project. See " - Future Power Supply; Cost of Power and Non-Firm Power - Clean Energy Project" below.

Westside Assets Solar Contract. The City executed a power purchase agreement with Westside Assets, LLC for 2 MW of solar energy in Kings County, California. On December 23, 2014, an amendment to the agreement clarified language and allowed for a revision to the construction schedule. This project reached commercial operation on May 9, 2016. The agreement term began in May 2016 and lasts for 25 years, expiring on June 30, 2041. Power under the agreement is priced at $91.00 per MWh fixed for the term less all CAISO charges, fees, debits, costs, penalties, and interest assigned to the project.

ARP-Loyalton Biomass Project. Through SCPPA, the City contracted for the purchase of 0.81 MW of energy from the 18 MW Loyalton Biomass Project over a five-year term. American Renewable Power owned and operated the project, located in the City of Loyalton, in Sierra County, California. The project reached commercial operation on April 20, 2018. Under the agreement, the City received its proportionate share of the energy output, capacity, and associated environmental attributes from the project at an estimated cost of $638,000 per year. The agreement assisted the City towards its compliance with Senate Bill 859, passed in 2016, which requires local publicly-owned electric utilities in California that serve more than 100,000 customers to procure a proportionate share of a cumulative total of 125 MW of electric generating capacity fueled from high hazard forest materials.

Calendar year 2020 marked the last year that the City received power from the Loyalton Biomass Project. In February 2020, the operator of the project, ARP-Loyalton Cogen LLC, and its parent company American Renewable Power LLC, filed petitions for relief under Chapter 11 of the Bankruptcy Code. Under a 2024 settlement approved by the Court, proceeds of certain letters of credit were returned to the Chapter 7 trustee after deducting the amounts due to SCPPA and its participants under the power purchase agreement and SCPPA was released from, among other things, any further obligations under the agreement. The power purchase agreement has also expired under its terms.

Desert Harvest II Solar Project. Through SCPPA, the City has contracted for the purchase of 36 MW of energy from the 70 MW Desert Harvest II Solar Facility, owned by Desert Harvest II, LLC and operated by EDF Renewable Services, Inc. and located near the town of Desert Center in Riverside County, California. The project reached commercial operation on December 17, 2020. The term of the agreement is twenty-five years. Under the agreement, the City receives its proportionate share of the facility energy output and associated environmental attributes from the project at an estimated cost of $1,851,000 per year.

Haypress Hydroelectric Contract. The City has contracted with EIF Haypress for 12.5 MW of hydroelectricity from 2 small power plants located in Sierra County, California. The plants operate as run-of-river hydro and as such, energy under the contract is "as available," similar to wind. Power deliveries began January 1, 2024, at a price of $60 per MWh with an annual escalator of 2.5% beginning in the second contract year. The contract expires on December 31, 2039.

Distributed Generation; Net Metering

The City's Net Energy Metering ("NEM") Program includes 43.9 MW of participating solar capacity installed to date, which represents 7.4% of the Electric System's peak aggregated load. Under the City's NEM Program, customers are able to receive either the full retail value credit shown in energy on their bill or cash compensation for the excess energy their system generates based on the City's avoided cost of renewable electricity. The City's NEM program includes a legislative goal of 29.6 MW, 5% of the

City's peak aggregated load, which was reached in May 2019. On January 1, 2021, the City launched its successor Net Energy Metering (NEM) Program, known as NEM 2.0, which continues to compensate customers for excess energy supplied from their distributed energy resources. Unlike the prior program, however, NEM 2.0 adjusts compensation based on the time of day, season, and market conditions, aligning payments more closely with the actual value of energy on the wholesale market.

Future Power Supply; Cost of Power and Non-Firm Power

As described above, the City currently has several contracts for firm purchases of power. These contracts accounted for approximately 81% of the City's total energy resources in the Fiscal Year ended June 30, 2025. In addition, the City can replace some of the energy otherwise available from its firm resources with energy purchased from other suppliers throughout the West. These short-term purchases are made under the Western Systems Power Pool Agreement and under bilateral agreements between the City and various suppliers. The City does this when the delivered cost of such energy is less than the variable cost of energy from its long-term resources or when additional energy is needed to meet the City's load. In the Fiscal Year ended June 30, 2025, the City purchased 595 GWh of short-term energy (about 19% of its total energy).

With the City's executed and planned divestiture of its interests in coal facilities, SJGS in 2017 and IPP expected in 2027, and the retirement of its Kraemer CT Plant at the end of 2019, the need for additional energy and capacity will be mostly offset by renewable resources as a result of California's Senate Bill 100 RPS legislation, requiring 60% of retail sales to be derived directly from renewable energy by 2030. The amount of capacity required to ensure the City's energy needs are met in the future, and to optimize its resource portfolio, will be met largely by short- and mid-term bilateral agreements. These types of agreements will provide the City with added flexibility to better manage its Electric System resource portfolio as its load profile changes over time.

The City anticipates fulfilling its customers' energy needs through dispatching power from generating plants in which it has acquired (or may in the future acquire) an ownership share, from power sales agreements, or from short-term (monthly, weekly, daily or hourly) purchases it makes on the spot market. The cost of obtaining the necessary energy will depend upon contract requirements and the current market price for energy. Spot market prices are dependent upon such factors as the availability of generating resources in the region and weather conditions such as ambient temperatures and the amount of rainfall or snowfall. Generating unit outages, dry weather, hot or cold temperatures and time of year can all adversely impact the supply and price of energy. There is no assurance that low cost energy will be available to the City in the future, though as a participant in the Western Systems Power Pool the City will have access to market priced power. The City currently has no authority to hedge pricing for either electricity or fuel utilizing financial products. However, given that the City is fully resourced to meet its retail obligations, the amount of energy procured through market mechanisms is restricted to short durations, exclusively transacted on a spot market basis where the risk exposure for price variances is limited and can be remedied almost immediately. With respect to fuel, as described under "Fuel Supply" below, the City has procured a number of resources for long-term supplies for a portion of the natural gas requirements for the Electric System that act as a hedge against short-term price variances by providing a guaranteed supply source with a fixed known price.

Clean Energy Project. On May 20, 2024, the City entered into an electricity supply agreement with SCPPA (the "Clean Energy Purchase Contract") for the purchase of renewable energy and related attributes pursuant to SCPPA's Clean Energy Project, which is structured to assist the City with obtaining a long-term supply of power at favorable prices. Under the Clean Energy Project, SCPPA issued its $592,270,000 Southern California Public Power Authority Clean Energy Project Revenue Bonds, Series 2024A to finance the prepayment of approximately thirty years of electricity deliveries, which SCPPA will sell to the City over the term of such deliveries, in amounts and at prices as set forth in the Clean Energy

Purchase Contract. The total quantity of prepaid electricity expected to be delivered during the initial delivery period, which commenced on October 1, 2024 and ends on August 31, 2030 or upon earlier termination of the Clean Energy Purchase Contract, is an estimated 1.9 million MWh of electricity. The electricity that SCPPA will be selling to the City during the initial delivery period will be obtained through the assignment of two existing power purchase agreements of the City: a Renewable Power Purchase and Sale Agreement, between the City and Bowerman Power LFG, LLC, executed by the City in March 2014, and a Consolidated, Amended, and Restated Power Purchase Agreement, dated as of December 15, 2009, among the City, Brea Power Partners, L.P. and Brea Power II, LLC. The City is the only participant in the Clean Energy Project, and the City's payment obligations under the Clean Energy Purchase Contract are payable only for electricity actually received thereunder, solely from Electric System revenues.

Roadhouse Energy Storage Project. In May 2024, the City executed a contract with Roadhouse Energy Storage, LLC, a subsidiary of NextEra Energy Resources, LLC, to design, construct, own, operate, and maintain a 300 MW battery energy storage system and sell to the City the project's energy capacity, resource adequacy, and associated attributes over a twenty-year delivery term. The project will be located on twenty acres of private land in an industrial area in Ontario, California, and requires the developer to meet performance guarantees, through augmenting the batteries as needed, for sufficient capacity and availability over the entire term. Additionally, the project qualifies as a local capacity resource given its location in the eastern Los Angeles Basin and has deliverability status with the CAISO. The City also retains operational flexibility to dispatch the battery system when needed but is not responsible for decommissioning the system following the end of the contract term. The contract is structured at a flat price of $18.76 per kW-month with no escalation. The City anticipates that the project will commence commercial operation in mid-2027 and enhance operational flexibility and integration of renewable energy.

Fuel Supply

The SCPPA Magnolia Power Project and Canyon Power Project are primarily fueled by natural gas. The City is a participant in SCPPA's Natural Gas Reserves Project and SCPPA's Prepaid Natural Gas Project, which provide the City with approximately 2,150 MMBtu of natural gas daily, or approximately 19% of the City's average daily baseload natural gas consumption. The remaining 81% of the City's average daily baseload natural gas consumption comes from short to medium term contracts (from one to ten years) and daily or monthly spot purchases.

Natural Gas Reserves Project. Through its participation in the SCPPA Natural Gas Reserves Project, the City has joined several members of SCPPA in acquiring natural gas reserves as a source of long-term supply of gas at a levelized price to provide fuel for the Magnolia Power Project. As a base-load combined-cycle facility, the City's share of fuel requirements for operating the Magnolia Power Project amounts to approximately 4.5 billion cubic feet of natural gas per year. Part of the City's overall natural gas portfolio strategy is to provide a portion of that natural gas through long-term, fixed price, gas supplies, either through long-term gas supply contracts or gas reserve field acquisitions. The SCPPA Natural Gas Reserves Project includes SCPPA's leasehold interests in (i) certain natural gas resources, reserves, fields, wells and related facilities located near Pinedale, Wyoming (the "Wyoming Subproject") and (ii) certain natural gas resources, reserves, fields, wells and related facilities in (or near) the Barnett Shale geological formation in Texas (the "Texas Subproject"). On June 7, 2005, the City entered into a gas sales agreement with SCPPA pursuant to which the City purchased on a "take-or-pay" basis its entitlement share of the production capacity of the related leasehold interests in the gas reserve fields and related facilities. Pursuant to the gas sales agreement, the City's entitlement share in the Wyoming Subproject was acquired at a cost of approximately $16.4 million. The City has taken delivery of this gas since July 2005. The City's entitlement share in the Texas Subproject, which was subsequently acquired at a cost of approximately $18.6 million, also aids in supplying the City's gas needs for the Magnolia Power Project. The City's gas sales agreement with SCPPA for both the Wyoming Subproject and Texas Subproject expires in 2032. On February 6, 2008, SCPPA issued revenue bonds for the benefit of the City and two of the other Natural Gas

Reserves Project participants in simultaneous financings in order to finance their respective shares of the acquisition costs of the Natural Gas Reserves Project.

Prepaid Natural Gas Project. The City and several members of SCPPA completed a prepaid natural gas financing to secure another source of long-term supply of gas to provide fuel for the Magnolia Power Project and other gas-fired generation stations. In connection with the prepaid natural gas financing, the City purchases on a “take-and-pay” basis natural gas acquired by SCPPA pursuant to the terms of a prepaid natural gas sales agreement between SCPPA and J. Aron & Company (“J. Aron”) at a discount from the spot price over a term of approximately 27 years (as a result of restructuring as described below) beginning on July 1, 2008. On October 22, 2009, the Prepaid Natural Gas Sales Agreements between SCPPA and J. Aron were restructured to provide an acceleration of a portion of the long-term savings, reduce the remaining volumes of gas to be delivered and shorten the overall duration of the agreements. As a result of the restructuring, a portion of the bonds issued by SCPPA with respect to the Prepaid Natural Gas Project was discharged. On September 19, 2013, the transaction was further restructured, as a result of which approximately $561,000 was remitted to the City from a lump sum payment received by SCPPA from the gas supplier. The City’s restructured natural gas supply agreement with SCPPA is expected to provide approximately 13% of the City’s historical gas requirements for the Magnolia Power Project.

Renewable Biomethane. The City executed a renewable Biomethane Purchase and Sale Agreement with SoCal Biomethane (the “Biomethane Agreement”), a subsidiary of Anaergia, Inc., to purchase renewable biomethane derived from food waste, which has been diverted from landfills to a digestions and gas production facility outside of the City. The Biomethane Agreement was assigned from SoCal Biomethane to Rialto Bioenergy Facility, LLC (“RBF”) pursuant to the Assignment and Assumption Agreement dated November 13, 2018, by and among SoCal Biomethane, RBF, and the City. The renewable Biomethane Agreement provides for the purchase of up to 210,240 MMBtu per year at an initial price of $12.74/MMBtu starting in the Fiscal Year ending June 30, 2021, which escalates annually by an average of 1.4% over the 20-year term of the agreement. The City terminated the Biomethane Agreement effective November 2, 2022. The City determined that RBF could not meet their contractual obligations, as a lack of sufficient feedstock hindered production and delivery of biomethane.

Transmission Resources

Southern Transmission System. The City is a participant in SCPPA’s Southern Transmission Project. The Southern Transmission System (“STS”) is an approximately 490-mile, ±500-kV DC transmission line that extends from IPP near Delta, Utah to the Adelanto Substation in Southern California, together with an AC/DC converter station at each end of the transmission line. The STS is owned by IPA and is one of three major components of IPP. LADWP operates and maintains the STS under contract with IPA. In connection with its entitlement to IPP, the City assigned its entitlement to capacity of the STS to SCPPA, in exchange for which SCPPA agreed to make payments-in-aid of construction of the STS and issued revenue bonds to finance the costs thereof. Pursuant to a transmission service contract with SCPPA, the City acquired a contractual entitlement to 17.647% of the transfer capability of the STS which obligates the City to pay the costs of its share of the transfer capability (including operating costs and debt service costs on bonds issued by SCPPA for the project) on a “take-or-pay” basis as an operating expense of the Electric System. The transfer capability of the STS is currently approximately 2,400 MW (as a result of upgrades completed in December 2010). The City’s entitlement in SCPPA’s share of the transfer capability of the STS is approximately 423.5 MW. The City’s contractual entitlement and obligation extends until 2027, consistent with the timeframe of the current power purchase agreements with IPA. See “Power Supply Resources – Non-City Owned Resources - Intermountain Power Project” above.

Mead-Adelanto Project, ***Authority Interest (Multiple Members)***. The City is a participant in SCPPA’s member-related interest in the Mead-Adelanto Project. The City entered into a transmission service contract with SCPPA that provides the City with an entitlement share (approximately 118 MW) of

SCPPA's member-related ownership interest (the "Authority Interest (Multiple Members)") in the Mead-Adelanto Project and obligates the City to pay for its share of the costs of SCPPA's Authority Interest (Members) in the Mead-Adelanto Project (including operating costs and debt service costs on bonds issued by SCPPA for the project) on a "take-or-pay" basis as an operating expense of the Electric System. The City's entitlement share is 9.1666% of SCPPA's 67.9167% Authority Interest (Multiple Members) in the project. The City's transmission service agreement with SCPPA for the Mead-Phoenix Project runs through October 31, 2030. The City uses the Mead-Adelanto Project for the transmission of energy purchased by the City.

Mead-Phoenix Project, Authority Interest (Multiple Members). The City is a participant in SCPPA's member-related interest in the Mead-Phoenix Project. The Mead-Phoenix Project is an approximately 256-mile, 500-kV AC transmission line that extends from the Westwing Substation (in the vicinity of Phoenix, Arizona), connects with the Mead substation near Boulder City, Nevada and terminates at the Marketplace Substation nearby. SCPPA executed an ownership agreement providing it with an 18.3077% member-related ownership share in the Westwing-Mead project component, a 17.7563% member-related ownership share in the Mead Substation project component, and a 22.4082% member-related ownership share in the Mead-Marketplace project component (collectively, the "Authority Interest (Multiple Members)") in the Mead-Phoenix Project. The Mead-Phoenix Project has an estimated transfer capability of 1,923 MW (as a result of certain upgrades completed in 2009). The City entered into a transmission service contract with SCPPA that provides the City with an entitlement to approximately 47 MW of transfer capability of the Mead-Phoenix Project and obligates the City to pay for its share (approximately 24.2%) of the costs of SCPPA's Authority Interest (Members) in the Mead-Phoenix Project (including operating costs and debt service costs on bonds issued by SCPPA for the project) on a "take-or-pay" basis as an operating expense of the Electric System. The City's entitlement shares in the three components of the Mead-Phoenix Project are as follows: 3.615% of the Westwing-Mead project component, 8.8781% of the Mead Substation project component and 5.9395% of the Mead-Marketplace project component, respectively, of the Authority Interest (Multiple Members) in the project. The City's transmission service agreement with SCPPA for the Mead-Phoenix Project runs through October 31, 2030. The City uses the Mead-Phoenix Project for the transmission of energy purchased by the City.

Anaheim's CAISO Arrangements

The CAISO began operations on March 31, 1998. The fundamental purpose of the CAISO is to operate the transmission system in a manner that is independent of the interests of the owners of the transmission facilities to buy or sell energy. The CAISO provides transmission service and related ancillary services to all users, including the City, on a non-discriminatory basis.

In June 2002, the City notified the CAISO of its intent to become a Participating Transmission Owner ("PTO") by turning over operational control of the City's transmission entitlements. In November 2002, the City executed the Transmission Control Agreement between the CAISO and the PTOs. On January 1, 2003, the City became a PTO under the CAISO tariff by turning over operational control of its transmission entitlements to the CAISO. In return, the City receives payment of its revenue requirement for such facilities from the CAISO. The City now obtains all of its transmission scheduling requirements from the CAISO, and it procures additional required ancillary services from the CAISO or from the open competitive market. On May 1, 2020, APU submitted a proposal to the Federal Energy Regulatory Commission ("FERC") to revise its transmission revenue requirement. Effective July 1, 2020, FERC issued an order accepting APU's proposed transmission revenue requirement.

Customers and Energy Sales

The Electric System serves the entire area within the City limits (an area of approximately 50 square miles) as well as small portions of unincorporated Orange County adjacent to the City. Tables 4 and 5 below set forth the average number of customers and total electrical energy sold (in GWh) during the five fiscal years shown.

TABLE 4
AVERAGE NUMBER OF CUSTOMERS[1]

	Fiscal Year Ended June 30,				
	2025	**2024**	**2023**	**2022**	**2021**
Residential	107,148	105,839	105,422	104,561	103,666
Commercial	17,541	17,498	17,500	17,557	17,466
Industrial	264	269	290	273	271
Other	101	109	110	112	112
Other Utilities	11	11	11	11	11
Total – All Classes	125,065	123,726	123,333	122,514	121,526

(1) Average number of meters as a proxy for number of customers.
Source: Anaheim.

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TABLE 5
TOTAL ENERGY SOLD
(GWh)

	Fiscal Year Ended June 30,				
	2025	**2024**	**2023**	**2022**	**2021**
Residential	616	586	637	600	630
Commercial	732	717	731	706	660
Industrial	788	811	856	851	739
Other[(1)]	1	1	1	1	1
Other Utilities[(2)]	651	421	470	524	622
Total – All Classes[(3)]	2,788	2,536	2,695	2,682	2,652

(1) This category includes streetlights (which comprise 91% of this category) as well as outdoor lights.
(2) Reflects wholesale sales activity under prevailing market conditions.
(3) The difference between the total GWh generated and purchased shown in Table 3 captioned "Total Gigawatt Hours (GWh) Generated and Purchased and Peak Demand (MW)" and total energy sold as shown in this Table 5 is due to transmission and distribution system losses, wholesale transactions, and renewable energy credits ("RECs").
Source: Anaheim.

During the Fiscal Year ended June 30, 2025, the City satisfied 100% of its power requirements for serving retail customers through a combination of long-term and short-term firm and non-firm power purchases.

Wholesale Power

From time to time, the City has the opportunity to purchase power from and sell power to a number of power marketing firms, independent power producers, and other electric utilities, and to enter into contracts for the forward purchase and sale of electricity. The City recognizes that its wholesale market activities give rise to certain risks and has committed resources to mitigate them through the establishment of a formal risk management program. Wholesale power trading optimizes the value of the utility's assets to cost-effectively serve its retail load. The City Council approved a risk management policy (the "Policy") to provide policy guidance with respect to its wholesale trading activities. Pursuant to the Policy, the City established a Risk Management Committee (composed of the Public Utilities General Manager, the City Finance Director, the City Attorney, the Anaheim Public Utilities Assistant General Managers of Finance & Energy Resources and Administration & Risk Services, the Integrated Resources Manager, the Financial Services Manager, and the Chief Risk Manager) to oversee the City's Wholesale Energy Risk Management Program (the "Program") which governs all proposed power purchase agreements, whether for retail or wholesale purposes. Pursuant to the Policy, the Program approved by the Risk Management Committee governs the various functions of the trading operations. The Policy and Program are intended to: (a) provide a common risk management infrastructure to facilitate management control and reporting; (b) create a procedure to evaluate the creditworthiness of the counterparties, and to monitor and manage the aggregate credit exposure; (c) establish a corporate culture exemplifying best practices in risk management; (d) create a mechanism to identify market-related opportunities within the City's overall exposure balance or "book"; and (e) develop an effective, streamlined ability to timely commit to transactions. The Program establishes guidelines for, among other things, authorized transaction limits, acceptable counterparty creditworthiness standards and requirements for limits on credit exposure to any individual counterparty. Most of the City's short-term purchase and sale transactions for wholesale power opportunities are 30 days or less.

Major Customers and Economic Conditions

APU serves a diverse customer base from a variety of industries, including tourism, hospitality, medical facility, aerospace, and telecom sectors. For the Fiscal Year ended June 30, 2025, the top 10 largest power customers of the Electric System, in terms of kilowatt hour ("kWh") sales, accounted for approximately 17.1% of the Electric System's total energy sales.

A major development project occurring in Anaheim is OCVibe, a planned 95-acre development that includes new homes, shopping, dining, entertainment, hotels, office space, and parks adjacent to the Honda Center. This $4-billion expansion proposes to add 1,500 apartments with affordable housing options; four parking structures and surface lots to add more than 11,000 parking spaces; 20 acres of publicly accessible parks, trails, plazas, and other spaces; a new 5,700-seat concert venue; more than 35 restaurants with 170,000 square feet of indoor and outdoor dining space; two new hotels collectively adding 550 rooms; 1.2 million square feet of office space; and more than 80,000 square feet of shopping options. A phased opening is planned for 2028, when the Honda Center is slated to host indoor volleyball for the 2028 Summer Olympics.

Another major project is DisneylandForward, a multiyear public planning effort to expand and update Disneyland theme parks, hotel offerings, entertainment, parking, restaurants, and more. The project proposes a $1.9 billion plus investment in Anaheim over 10 years. It includes updating land use approvals from the 1990s to allow Disneyland Resort to build attractions or hotels on land originally designated for parking or other purposes.

Electric Rates and Charges

Description of Rates and Charges. The City is obligated by the Charter and by certain resolutions of the City Council under which it has electric revenue bonds outstanding to establish rates and collect charges in an amount sufficient to service the City's Electric System indebtedness, to meet its expenses of operation and maintenance and to pay other obligations payable from gross revenues, with specified requirements as to priority and coverage. The City Council establishes electric rates, which are not subject to regulation by the CPUC or by any other state agency.

The rates charged by the City to its customers are also not subject to approval by any federal agency; however, the Public Utility Regulatory Policies Act ("PURPA") requires state regulatory authorities and nonregulated electric utilities, including the City, to consider certain rate-making standards and to make certain determinations in connection therewith. The City believes that it is operating in compliance with PURPA.

The Charter requires that electric rates be based upon the cost of service to the various customer classes. As provided in Section 909 of the Charter, the City's Public Utilities Board has the power and duty to conduct all public hearings for the electric utility, including those for the consideration of utility rates and to make recommendations to the City Council concerning electric rates adopted by the City Council.

The Anaheim Electric System has a number of base rate schedules. Generally, all costs of the Anaheim Electric System, including power supply costs, are recovered through the application of these base rates. The City's customer rates also include a Rate Stabilization Adjustment ("RSA") that increases or decreases specifically for the recovery of the respective fluctuations in power supply, relevant operational costs, and environmental mitigation costs to meet specified financial performance indicators and goals. The goals stated within the rate schedule include the maintenance of debt service coverage ratios no less than 1.5 times and a balance in the account for deferred inflows (RSA collections) equal to approximately $50 million.

The RSA contains two components: the Power Cost Adjustment ("PCA") and the Environmental Mitigation Adjustment ("EMA"). The PCA can increase up to ½¢ per kWh in any 12-month period to collect for changes in power production costs, purchased power costs, regulatory compliance costs, debt service and any other costs involved in delivering energy. Additionally, if the Electric System's power supply or fuel costs increase by more than 10% over originally budgeted levels for a period of one month or longer or if the Electric System loses a major resource, such as a generation or transmission unit, then the PCA may increase by an additional 1¢ per kWh over and above the current ½¢ limit until all associated costs are collected at which time the PCA will be reduced to its previous level. This provision recovered costs related to an outage at IPP. The second component of the RSA, the EMA, allows for the recovery of environmental mitigation costs, such as projected greenhouse gas emissions costs, the marginal cost differential between renewable power and traditional carbon-based power, and environmental mitigation costs imposed by regulatory bodies, legislative mandates or judicial settlements, orders or decrees. The EMA is structured similarly to the PCA in that the annual limit of the increase is ½¢ per kWh unless costs increase by more than 10% of projections, at which point the EMA's limit on annual increases may be increased by an additional 1¢ per kWh until all associated costs are collected, and at that time the EMA will be reduced to its previous level.

The RSA collections are treated as deferred inflows for accounting purposes and are used by management to mitigate material fluctuations in the cost of energy, loss of revenues or unbudgeted costs including the unexpected long-term loss of a generating facility, unplanned limits on the ability to transmit energy to the City, or disasters that could otherwise negatively affect the revenue stream. At management's discretion, amounts in the RSA accounts may be withdrawn and recognized as gross revenues of the Electric System in order to maintain sufficient debt service coverage ratios. As of June 30, 2025, the balance in the RSA regulatory credit account, after recognition of RSA revenue for the fiscal year ending on that day, was approximately $110.0 million.

The RSA provides the City with operational and billing flexibility. With respect to any RSA adjustment, the City first considers the result on customer bills with a goal of maintaining total electric charges that are competitive with those of other utilities in the region. Any change indicated by the RSA calculation is reviewed against other known long-term factors prior to any automatic implementation of rate changes. This allows the City to blend forecasted increases or decreases in the projected power supply or operational costs to meet the financial requirements of the City and mitigate future fluctuations in electrical costs to customers. The General Manager has the authority to adjust the RSA within prescribed guidelines.

Effective May 1, 2024, the City updated its electric rate schedule, lowering certain variable rate components (such as the PCA and the EMA) with corresponding increases to base rates to better align with current costs. The PCA charge has been set to zero for all customer classes, and the EMA charge is 0.0005¢ per kWh for all customer classes. While related upward adjustments have been incorporated into the existing base rates, the PCA and EMA charges remain available as described above for potential future adjustments when needed. In addition, all classes pay an undergrounding surcharge equal to 4% of base rate charges (exclusive of RSA) in order to fund the conversion of overhead power lines into underground lines throughout the City. The City does not impose a utilities' user tax.

The City's current primary rate schedules for residential, commercial and industrial customers of the Electric System are set forth in Table 6 below.

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TABLE 6
PRIMARY RATE SCHEDULES FOR RESIDENTIAL, COMMERCIAL AND INDUSTRIAL CUSTOMERS
(As of June 30, 2025)

Type and Description of Service		
Domestic Services Single Family Customers (Basic):		
Customer Charge, per meter, per month	$ 8.00	
Energy Charge (added to Customer Charge):		
First 10 kWh per day, cents per kWh	14.00	
All Excess kWh, cents per kWh	21.49	
General Service Small Commercial Customers:		
Customer Charge, per meter, per month	$ 24.00	
Energy Charge (to be added to Customer Charge):		
All kWh, cents per kWh	19.60	
General Service Medium Commercial Customers:		
Customer Charge	$ 56.00	
Demand Charge (added to Customer Charge)		
First 15 kW or less of billing demand	166.00	
All excess kW of billing demand per kW	17.13	
Energy Charge (added to Demand Charge)		
All kWh, cents per kWh	13.78	
General Service Large Commercial and Industrial Customers:		
Customer Charge, per meter, per month	$ 370.00	
Demand Charge (to be added to Customer Charge):		
First 200 kW or less of billing demand	3,726.00	
All excess kW of billing demand, per kW	21.10	
Energy Charge (to be added to Demand Charge):		
For the first 540 kWh per kW of billing demand, cents per kWh	13.03	
All excess kWh, cents per kWh	9.00	
	Summer	**Winter**
Commercial Optional Time of Use Rate:		
Customer Charge, per meter, per month:	$350.00	$350.00
Demand Charge (added to Customer Charge):		
Non-Time related Maximum Demand, per kW	11.00	11.00
Plus all on-peak billing demand, per kW	19.95	N/A
Plus all mid-peak billing demand, per kW	6.98	10.93
Plus all off-peak billing demand, per kW	N/A	N/A
Energy Charge (added to Demand Charge):		
All on-peak energy, cents per kWh	17.32	N/A
Plus all mid-peak energy, cents per kWh	13.60	14.56
Plus all off-peak energy, cents per kWh	9.20	9.20

Source: Anaheim.

Average Billing Price. The table below sets forth the average billing price per kWh for the various customer classes during the five fiscal years shown (taking into account the PCA, the EMA and the 4.00% undergrounding surcharge).

TABLE 7
AVERAGE BILLING PRICE (CENTS) PER KILOWATT-HOUR
(RETAIL SALES)

	Fiscal Year Ended June 30,				
	2025	**2024**	**2023**	**2022**	**2021**
Residential	19.73	20.09	19.16	18.28	18.13
Commercial	21.22	21.38	19.86	19.61	19.38
Industrial	17.99	18.82	17.00	16.59	16.49
Other	19.17	21.23	19.44	16.70	16.63
System Averages	19.59	20.27	18.56	18.05	17.94

Source: Anaheim.

Cost Recovery and Reserves. APU's electric rates include components that largely decouple revenues from sales and allow for the timely recovery of costs and achievement of financial goals. The City Council authorized APU to employ this rate stabilization adjustment mechanism when needed, allowing for timely cost recovery, customer bill stability, and the ability to raise approximately $65 million per year (based on historical electricity demand) without requiring City Council action. These rate mechanisms, coupled with financial reserves (including the rate stabilization adjustment balance) equal to approximately 200 days of operating expenses and a $100 million revolving line of credit with Wells Fargo Bank, N.A., provide APU with the means to offset potential lost revenue from reduced retail sales and/or increased costs.

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Capital Improvements Plan

As part of its capital planning process, the City identified the following Electric System capital improvement projects scheduled through the fiscal year ending June 30, 2030 (the "Five-Year Plan"), totaling approximately $448.6 million:

	Five-Year Plan (1) 2025-26 through 2029-30 ($000)
Substation Improvements	$ 151,169
System Undergrounding	76,152
Electric Facilities & Streetlights	64,902
Cable Replacement & System Expansion	54,859
Transmission & Distribution	47,807
Transformer Replacement	37,726
System Protection, Automation, & Telecom	16,033
Total	$448,649

(1) The five-year plan shown represents projected capital expenditures only, not City Council adopted budgets. As such, figures may change based on timing of projects, related expenditures, and re-prioritization of projects.

The City's electric capital program aims to improve electric service reliability, enhance system resiliency, improve operational efficiencies, support system growth, and integrate renewable resources. Transmission and distribution projects replace aging overhead electrical and communication facilities with new underground facilities to improve overall system reliability, public safety, and aesthetics. Projects involving the Electric System's distribution substations include enhancements to existing substations that will improve reliability and provide sufficient flexibility and capacity for future electric load growth. System undergrounding projects place overhead electrical and communication infrastructure along Anaheim's major thoroughfares underground, including in high fire-threat zone areas for wildfire mitigation. Electric facilities and streetlights include construction of a backup operations and field station facility and street light additions and upgrades. Cable replacement projects replace aged and deteriorated cable, utilizing more resilient conduits. The transformer replacement program replaces existing overhead transformers to reduce the likelihood of emergency repairs. System Protection and Automation includes the electric system automation, protection, and Supervisory Control and Data Acquisition ("SCADA") upgrades to enhance the resiliency and flexibility of the electric distribution system, while telecommunication projects upgrade and expand the fiber optic infrastructure to enable automation.

The City funds its capital plan through a combination of long-term financing, pay-as-you-go, and other resources such as grants. The City assesses and utilizes the capital markets on a periodic basis to fund appropriate capital projects based on its planning models. The City currently anticipates it will finance approximately 27% of the capital costs identified in the Five-Year Plan through existing and new bond proceeds. These projections may change based on deferrals of Electric System capital improvement projects or changes in the mix of financial resources used to fund capital projects.

Insurance

The Electric System participates in the City's self-insured workers' compensation and general liability program. The liability for such claims, including claims incurred but not reported, is transferred to the City in consideration of self-insurance premiums paid by the Electric System. Premiums for workers' compensation and general liability programs are charged to the Electric System by the City based on various allocation methods that include actual cost, trends in claims experience, exposure base, and number of participants. Premiums charged and paid totaled $4,539,000 and $4,224,000 for the years ended June 30, 2024 and June 30, 2025, respectively.

As of June 30, 2025, the City was fully funded for self-insured workers' compensation and general liability claims (self-insured retention levels of $2,000,000 per occurrence for workers' compensation claims and $1,000,000 per occurrence for general liability claims). Above these self-insured retention levels, the City's potential liability is covered through various commercial insurance and intergovernmental risk pooling programs. Settled claims have not exceeded total insurance coverage in any of the past three years, nor does management believe that there are any pending claims that will exceed total insurance coverage.

The City maintains an internal services fund to account for self-funded general liability claims and certain other items (the "Insurance Fund"). The unpaid claims liability included in the Insurance Fund is based on the results of actuarial studies and includes amounts for claims incurred but not-reported, known-claim development, and allocated loss adjustment expenses. Claims liabilities are calculated using a discount rate of 2.25% and consider the effects of inflation, multiyear loss development trends, and other economic and social factors. It is the practice of the City to obtain full annual actuarial studies annually for its retained levels for general liability and workers' compensation exposures. "Premiums" are charged by the Insurance Fund to City departments, including APU, using allocation methods that include actual costs, claims experience and applicable exposure bases.

Wildfire Mitigation Measures

APU has implemented comprehensive wildfire mitigation measures to reduce the risk of utility-associated wildfires. A portion of the Electric System service area falls within geographical areas classified by the CPUC's Fire Threat Map as "Tier 2" or "Tier 3" fire-threat zones (FTZs), representing areas of elevated or extreme wildfire risk. Within the four Tier 3 FTZs in the City's boundaries, which account for 13.86% of the City, approximately 98.1% of APU-owned power lines are underground. The remaining above-ground power lines in these Tier 3 FTZs are de-energized unless required for electricity distribution, significantly reducing the risk of wildfire ignition. An additional 0.64% of the service area is identified as a Tier 2 fire-threat zone.

APU actively monitors conditions that may require de-energizing lines and has established operational protocols for immediate power shutoffs within FTZs. These protocols are documented in APU's wildfire mitigation response procedures, outlining both operational steps and communication plans.

APU's wildfire emergency preparedness strategy includes annual workforce emergency response training, flexibility to re-route power during outages and emergencies with minimal service disruption, and the ability to disable automatic reclosing of protective relays on certain transmission lines in Tier 3 FTZs during dangerous weather conditions — ensuring power is only restored after manual inspection confirms safe operation. APU coordinates closely with the City's Anaheim Fire & Rescue agency (AF&R) for structure fires and other emergencies, regardless of wildfire risk, and participates in a citywide safety committee with AF&R, and the City's police, public works, and safety agencies to address public safety concerns quarterly.

Additionally, while Edison operates 500-kV high-voltage transmission lines through the East Anaheim FTZ, APU customers are not affected by Edison's public safety power shutoffs. Anaheim relies on regional transmission service via Edison, but redundant transmission paths that bypass FTZs reduce the risk of losing service. APU and Edison conduct annual meetings to review operational and communication procedures related to wildfire mitigation.

Pursuant to California Senate Bill 901, which became law in 2018 and requires all public and private utilities to assess their geographical area of service where overhead electrical lines and equipment may pose significant wildfire risk, APU presents a wildfire mitigation plan ("WMP") annually to its Public Utilities Board for approval and adoption. The Anaheim Public Utilities Board's most recent approval of APU's WMP was on June 25, 2025. Additionally, California Public Utilities Code Section 8387 requires an independent evaluation from an evaluator with expertise in electrical infrastructure safety every three years. APU's last independent evaluation occurred in 2023, with the evaluator concluding that Anaheim's 2023 WMP was "comprehensive" and met CPUC requirements. The next independent evaluation is scheduled for the 2026 WMP.

As part of its 2025 WMP, APU updated its Wildfire Threat Zone map to reflect the more conservative classification between CalFire's Fire Hazard Zones issued on March 24, 2025, and CPUC's High Fire-Threat District Map last updated in 2018. In July 2025, the City Council adopted the CalFire map, through amending various sections of the municipal code.

Transfers to the General Fund

Transfers of Electric System funds to the City's General Fund occur on a semi-annual basis. Under the Charter, annual transfers may not exceed 4% of gross revenues of the electric utility for the prior fiscal year.

Indebtedness; Joint Powers Agency Obligations

Direct Obligations. As of June 30, 2025, in addition to its obligations under its joint powers agency contracts (see "– Joint Powers Agency Obligations" below), the City had outstanding $579,235,000 principal amount of long-term obligations payable from Electric System revenues, consisting of installment purchase payments ("Qualified Obligations") payable by the City under installment purchase agreements with the Anaheim Housing and Public Improvements Authority ("AHPIA") or the California Municipal Finance Authority ("CMFA") relating to bonds issued by AHPIA or CMFA for the benefit of the Electric System, which are payable from surplus Electric System revenues after payment of maintenance and operations expenses of the Electric System and the replenishment of certain reserves and other funds.

The outstanding Qualified Obligations are summarized in the table below.

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TABLE 8
OUTSTANDING QUALIFIED OBLIGATIONS
(as of June 30, 2025)

Issue	Date of Installment Purchase Agreement	Principal Amount Outstanding
California Municipal Finance Authority Revenue Refunding Bonds, Series 2014-A (City of Anaheim Electric Utility Distribution System Refunding)	10/01/14	$ 8,825,000
California Municipal Finance Authority Revenue Refunding Bonds, Series 2015-B (City of Anaheim Electric Utility Distribution System Refunding and Improvements)	06/01/15	37,155,000
Anaheim Housing and Public Improvements Authority Revenue Refunding Bonds, Series 2017-A (Electric Utility Distribution System Refunding)	12/01/17	25,230,000
Anaheim Housing and Public Improvements Authority Revenue Bonds, Series 2020-A (Electric Utility Distribution System Improvements)	03/01/20	38,865,000
Anaheim Housing and Public Improvements Authority Revenue Refunding Bonds, Series 2020-B (Electric Utility Distribution System Refunding)	03/01/20	46,105,000
Anaheim Housing and Public Improvements Authority Revenue Refunding Bonds, Series 2020-C (Electric Utility Distribution System Refunding)	03/01/20	21,955,000
Anaheim Housing and Public Improvements Authority Revenue Bonds, Series 2022-A (Electric Utility Distribution System)	04/01/22	155,145,000
Anaheim Housing and Public Improvements Authority Revenue Bonds, Series 2022-B (Electric Utility Generation System)	04/01/22	69,065,000
Anaheim Housing and Public Improvements Authority Revenue Refunding Bonds, Series 2022-D (Electric Utility Distribution System Refunding) (Federally Taxable)	04/01/22	33,415,000
Anaheim Housing and Public Improvements Authority Revenue Refunding Bonds, Series 2022-E (Electric Utility Distribution System Refunding) (Forward Delivery)	04/01/22	34,095,000
Anaheim Housing and Public Improvements Authority Revenue Refunding Bonds, Series 2024-A (Electric Utility Distribution System Refunding)	08/20/24	109,380,000
Total		$ 579,235,000

Source: Anaheim.

The City has entered into an Amended and Restated Revolving Credit Agreement, dated as of December 7, 2023 (the “Revolving Credit Agreement”) with Wells Fargo Bank, National Association (the “Credit Bank”), under which the City may borrow up to $100,000,000 for purposes of the Electric System. The repayment obligation of the City for amounts borrowed under the Revolving Credit Agreement for the Electric System is evidenced by Electric Revenue Anticipation Notes of the City which are payable from and secured by surplus Electric System revenues on a basis that is junior and subordinate to the payment of the Qualified Obligations.

Any outstanding Electric System borrowings of the City under the Revolving Credit Agreement that have not been paid (which borrowings may be paid from, among other sources, proceeds of future long-term financings of the City) on or prior to the facility maturity date of the Revolving Credit Agreement (i.e., currently December 6, 2028, unless extended) will be automatically converted to term loans on such date, so long as no default or event of default by the City shall have occurred and be continuing and all representations and warranties of the City under the Revolving Credit Agreement are true and correct in all material respects as of such date.

The Revolving Credit Agreement is also available for Water System borrowings. Borrowings for the Water System will reduce the commitment available under the Revolving Credit Agreement by an amount corresponding to such Water System borrowing. As of August 1, 2025, there is no balance outstanding under the Revolving Credit Agreement.

Joint Powers Agency Obligations. As described herein, the City participates in or contracts with several joint powers agencies, including IPA and SCPPA. Obligations of the City under the agreements with IPA and SCPPA constitute maintenance and operation expenses of the Electric System payable prior to any of the payments required to be made with respect to the City’s outstanding direct Electric System obligations (including the Qualified Obligations and Electric Revenue Anticipation Notes). Agreements between the City and IPA and the City and SCPPA (other than the agreement relating to SCPPA’s Prepaid Natural Gas Project bonds and Clean Energy Project bonds) are on a “take-or-pay” basis, which requires payments to be made whether or not applicable projects are completed or operable, or whether output from such projects is suspended, interrupted or terminated. All of these agreements (other than the agreements relating to SCPPA’s Prepaid Natural Gas Project bonds, the Natural Gas Reserves Project bonds, the Canyon Power Project bonds and the Clean Energy Project bonds) contain “step-up” provisions obligating the City to pay a share of the obligations of a defaulting participant. The City’s participation and share of debt service obligation (without giving effect to any “step-up” provisions) for each of the joint powers agency projects in which it participates are shown in the following table.

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TABLE 9
OUTSTANDING DEBT OF JOINT POWERS AGENCIES AND ANAHEIM'S SHARE
(as of December 1, 2025)

	Principal Amount of Outstanding Debt	Anaheim's Participation[1]	Anaheim's Share of Principal Amount of Outstanding Debt[2]
Intermountain Power Agency			
Intermountain Power Project	$ 112,520,000	13.225%	$ 5,385,671[3]
Southern California Public Power Authority			
Southern Transmission System	72,190,000	17.647	12,739,369
Magnolia Power Project[4]	187,770,000	39.683	74,513,145
Prepaid Natural Gas Project[5]	219,555,000	16.500	36,226,575
Natural Gas Reserves	13,300,000	100.000	13,300,000
Canyon Power Project	222,885,000	100.000	222,885,000
Clean Energy Project[6]	591,720,000	100.000	591,720,000
Subtotal	1,307,420,000		951,384,089
Total	$ 1,419,940,000		$ 956,769,760

(1) Obligation is subject to increase upon default of another project participant (other than with respect to SCPPA's Prepaid Natural Gas Project bonds, the Natural Gas Reserves Project bonds, the Canyon Power Project bonds and the Clean Energy Project bonds).
(2) Reflects outstanding bonds and subordinated notes applicable to the City.
(3) Reflects net share of principal amount of outstanding debt after giving effect to amounts received from IPA's issuance of its Series K Notes in July 2025.
(4) Excludes bonds relating solely to City of Cerritos.
(5) Not a "take-or-pay" obligation; the City must pay for contracted natural gas only to the extent delivered.
(6) Not a "take-or-pay" obligation; the City must pay for contracted electricity only to the extent delivered.
Source: Anaheim; IPA.

For the Fiscal Year ended June 30, 2025, the City estimates that payments of debt service on its joint powers agency obligations totaled approximately $38.6 million. Annual debt service on the City's joint powers agency obligations is expected to decrease from this level to approximately $19.5 million in the Fiscal Year ending June 30, 2040. This projection assumes no future debt issuances and further assumes that all variable rate joint powers agency debt obligations remain hedged. Currently, all joint powers agency debt that Anaheim is a participant in is either fixed or fully-hedged if variable. Unreimbursed draws under liquidity arrangements supporting joint powers agency variable rate debt obligations bear interest at a maximum rate substantially in excess of the assumed rates stated above and may be subject to repayment to the liquidity provider over a significantly shorter period than the originally scheduled payment of principal on the related bonds. Interest rate swap agreements entered into by joint powers agencies in connection with hedged variable rate joint powers agency obligations may be subject to early termination. In the event of early termination of a joint powers agency interest rate swap agreement, the joint powers agency could be obligated to make a substantial payment to the applicable swap provider, a corresponding amount of which termination payment (proportionate to each project participants' participation share in the related project) could be due from the applicable project participants.

Accounting Policies

The Electric System's accounting records, financial transactions and billing are computerized. The City's independent auditor performs an audit of the Electric Utility Fund of the Electric System at the same time as the other financial statements of the City are audited.

Funds of the Electric System are separated from the General Fund of the City, and the books and records are maintained separate and apart from all other funds and accounts of the City.

For further information concerning the Electric System's financial position, see the audited financial statements of the Anaheim Electric Utility Fund for the Fiscal Year ended June 30, 2025 filed on the Electronic Municipal Market Access website of the Municipal Securities Rulemaking Board, currently located at http://emma.msrb org. *The foregoing internet address is included for reference only, and except as otherwise provided herein, the information on the internet site is not incorporated herein by this reference.*

Historical Financial Results

The following table shows a summary of the financial results of the Electric System for the five Fiscal Years ended June 30, 2021 through June 30, 2025. The table also sets forth the calculation of debt service coverage of outstanding Electric System obligations for these periods.

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TABLE 10
CITY OF ANAHEIM
ELECTRIC UTILITY FUND, FINANCIAL RESULTS OF THE ELECTRIC SYSTEM
($000)

	Fiscal Year Ended June 30,				
	2025	**2024**	**2023**	**2022**	**2021**
Revenues					
Sale of electricity:					
Residential	$118,403	$101,425	$106,124	$ 100,861	$ 99,110
Commercial	151,961	128,567	122,100	124,625	116,632
Industrial	138,449	127,324	120,366	122,338	112,698
Other	5,144	4,676	3,094	3,216	3,568
Other Utilities (wholesale)	10,427	14,105	35,320	20,640	27,286
Total revenue from sale of electricity	$424,384	$376,097	$387,004	$371,680	$359,294
RSA revenue recognized[1]	10,500	34,000	58,637	40,000	35,000
Other (including general interest income)[2]	46,778	46,834	43,081	33,503	40,937
Total gross revenues	$481,662	$456,931	$488,722	$445,183	$435,231
Expenses (excluding depreciation and amortization)					
Cost of purchased power[3]	$256,719	$242,074	$300,004	$271,293	$250,867
Fuel and generation[4]	-	-	265	399	68
Operations & Maintenance	75,953	74,723	56,883	46,052	57,909
Right of way fee	5,870	6,108	6,227	5,042	5,530
Total expenses	$338,542	$322,905	$363,411	$322,786	$314,374
Net revenues	143,120	$134,026	$125,311	$122,398	$120,857
Deposits to Renewal and Replacement Account	310	(713)	(246)	478	1,954
Surplus Revenues (a)	142,810	134,739	125,557	121,920	118,903
Qualified Obligations purchase payments (b)[5]	70,725	67,013	64,414	60,840	58,765
Second Lien Qualified Obligations (c)	-	-	-	-	-
Net revenues after debt service payments	72,085	67,726	61,143	61,080	60,138
Transfers (to) Anaheim General Fund	(17,198)	(21,221)	(16,994)	(15,239)	(16,667)
Transfers (to) from other Anaheim funds	1,949	507	253	1,422	179
Balance for other purposes	$ 56,836	$ 47,012	$ 44,402	$ 47,264	$ 43,650
Qualified Obligation (incl. Second Lien) debt service coverage (a/(b+c))	2.0x	2.0x	1.9x	2.0x	2.0x

(1) RSA is billed to customers through standard rates, and amounts collected are deferred and recorded as regulatory credits in the statement of net position. RSA revenue recognized, as shown, represents those amounts recognized as revenue and no longer recorded as regulatory credits. This revenue is typically recognized prior to fiscal year-end.
(2) The other revenues include transmission revenues, natural gas sales and interest income. Other revenue was restated to exclude capital grants from operation revenue based on GASB 34.
(3) Includes take-or-pay obligations with joint powers agencies. Cost of Purchased Power includes transmission costs and natural gas costs. Cost of Purchased Power reflects use of carbon allowance credits from the CARB to reduce renewable energy expenses.
(4) Fuel and generation includes all expenses associated with the operation of the Kraemer CT Plant and the SJGS Unit 4, which are no longer in operation.
(5) Refer to Table 8 herein for Qualified Obligations outstanding at June 30, 2025.
Source: Anaheim.

Management's Discussion of Fiscal Year 2024-25 Operating Results

Total net position for the Fiscal Year ended June 30, 2025 was $650.5 million, an increase of $65.1 million or 11.1% from the prior fiscal year. Revenue for the Fiscal Year ended June 30, 2025 was $492.7 million, an increase in total revenue of $14.6 million or 3.1% from the prior fiscal year due to several factors. Total retail sales increased by $51.5 million or 14.4% for the Fiscal Year ended June 30, 2025 compared to the prior fiscal year as a result of rate restructuring effective May 1, 2024, implemented in order to more effectively align the recovery of the Electric System's costs with the nature of the costs incurred. Total wholesale sales decreased by $3.7 million due to reduced available generation, which limited the amount of excess power the Electric System could sell into the wholesale market. Investment income had a net increase of $1.6 million, mostly due to a favorable investment environment. The Electric System recognized a gain of $5.3 million related to the reduction of a previously recorded obligation for the decommissioning of the Kraemer Combustion Turbine (CT) plant. In addition, capital contributions had a net decrease of $15.4 million. Rate stabilization revenue recognized decreased by $23.5 million, as a result of rate restructuring, allowing for a more stable and reliable revenue stream. The restructuring was designed to be revenue neutral for each customer.

Expenses for the Fiscal Year ended June 30, 2025, were approximately $406.5 million, an increase of $16.7 million or 4.3% from the prior fiscal year. The increase was primarily driven by higher purchased-power costs from the Intermountain Power Plant and an increase in renewable-resource purchases. The Electric System continues to manage its resource mix and procurement strategies to maintain cost stability while meeting Renewable Portfolio Standard (RPS) requirements. Operation, maintenance, and administration costs totaled $76.0 million, an increase of $1.2 million or 1.6% from the prior fiscal year. The increase is primarily due to salaries and related burdens from an increase in employee compensation under the current Memorandum of Understanding, which also led to higher payroll-related costs.

Labor Relations

As of June 30, 2025, APU has a total of 353 full-time and 52 part-time authorized positions. Of this total: the International Brotherhood of Electrical Workers ("IBEW") Local 47 represents, approximately, 214 full-time and 25 part-time employees; the American Federation of State, County, and Municipal Employees District Council 36 ("AFSCME") represents approximately 115 full-time and 10 part-time employees; and the Anaheim Municipal Employees Association ("AMEA") represents 6 full-time employees. The City of Anaheim and IBEW, Local 47 established a memorandum of understanding for the general unit effective January 1, 2023 through January 1, 2026, for the part-time customer service unit effective January 1, 2023 through December 31, 2025, and for the professional management and part-time management units effective January 20, 2023 through January 16, 2026. The memorandum of understanding with AMEA expired July 3, 2025. The City is currently in negotiations with AMEA, and the general terms and conditions of the expired agreement remain in effect until a successor agreement is reached. The City also approved a memorandum of understanding with AFSCME effective July 1, 2023 through June 30, 2027. The City has not experienced any strike, work stoppage or other labor action by APU's employees in the last five years.

Retirement Programs

Pension Plans. The City's permanent employees, including APU's Electric System employees, are covered by the California Public Employees Retirement System ("CalPERS") through agent multiple-employer defined benefit plans administered by CalPERS, which acts as a common investment and administrative agent for participating public employers within the State. CalPERS issues publicly available reports that include a full description of the pension plans regarding benefit provisions, assumptions and membership information that can be found on the CalPERS website at www.calpers ca.gov. *The foregoing* *internet address is included for reference only, and the information on the internet site is not incorporated by reference herein.*

The City's defined benefit pension plans, the Miscellaneous Plan, Police Safety Plan and Fire Safety Plan, provide retirement and disability benefits, annual cost-of-living adjustments, and death benefits to plan members (who must be public employees) and beneficiaries. No employees assigned to the Electric System participate in the Police Safety Plan or Fire Safety Plan. Benefit provisions and all other requirements of the plans are established by State statute and City ordinance. California legislation, the Public Employee's Pension Reform Act ("PEPRA") of 2013, implemented certain limits on the amount and types of compensation that may be included in calculating pension benefits and new formulas for the calculation of pension benefits, as well as certain contribution requirements for the sharing of pension benefit costs, for new employees hired on or after January 1, 2013 who meet the definition of a new member under PEPRA.

The cost of the Miscellaneous Plan is funded through bi-weekly contributions from employees and from employer contributions by the City. Miscellaneous Plan employees hired prior to January 1, 2013 are generally required to contribute 8.00% of their annual covered salary. Miscellaneous Plan members hired on or after January 1, 2013 and who have no prior membership in any California public employee retirement system are required to contribute 6.75% of their annual covered salary. The member contribution can be paid by the employee or by the City on the employee's behalf in accordance with applicable labor agreements. The majority of Miscellaneous Plan employees hired prior to January 1, 2013 contribute the full 8.00% employee contribution plus 4.00% of the employer contribution, for a total of 12.00%. For employees hired on and after January 1, 2013 that are required to contribute at an employee rate of 6.75% of annual covered salary, the entire 6.75% is paid by such employees. In accordance with applicable State law, the contribution rate for all public employers is determined annually by the actuary and is effective on the July 1 following notice of a change in rate. Funding contribution amounts are determined annually on an actuarial basis as of June 30 by CalPERS. The actuarially determined rate applied to annual payroll 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 actuarially determined remaining amounts necessary to fund the benefits for its members, using the actuarial basis recommended by CalPERS actuaries and actuarial consultants and adopted by the CalPERS Board of Administration. CalPERS establishes and amends the employer contribution rates. Beginning with Fiscal Year 2017-18, CalPERS began collecting employer contributions toward the plan's unfunded liability as dollar amounts rather than percentage of active payroll. Miscellaneous Plan provisions and benefits in effect at June 30, 2025 are as follows: the City's required employer contribution rate for the normal cost component of required contributions for the Miscellaneous Plan was approximately 12.61% of annual covered payroll for employees hired prior to January 1, 2013, and 12.61% of annual covered payroll for employees hired after January 1, 2013; the City's contribution to the unfunded accrued liability was approximately $44,046,000.

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The table below shows the recent history of the actuarial accrued liability, the market value of assets, the funded ratio and the annual covered payroll for the City's Miscellaneous Plan.

Valuation Date	Accrued Liability	Market Value of Assets	Unfunded Liability	Funded Ratio	Annual Covered Payroll
06/30/20	$1,543,927,000	$1,084,188,000	$459,739,000	70.2%	$124,700,000
06/30/21	1,619,285,000	1,308,881,000	310,404,000	80.8	111,733,000
06/30/22	1,681,617,000	1,183,362,000	461,482,000	71.9	119,690,000
06/30/23	1,741,021,000	1,230,615,000	510,406,000	70.7	133,453,000
06/30/24	1,815,111,000	1,322,020,000	493,091,000	72.8	147,681,000

Beginning with the June 30, 2013 valuation, CalPERS no longer uses an actuarial value of assets and instead uses the market value of assets to determine contribution rates per CalPERS' direct rate smoothing policy. Under its direct rate smoothing policy, CalPERS employs an amortization and smoothing policy that will pay for all gains and losses over a fixed 30-year period with the increases or decreases in the rate spread directly over a 5-year period.

The PERS Board adopted a new amortization policy effective with the June 30, 2019 actuarial valuation. Under the new policy, amortization payments are determined as a level dollar amount. Investment gains or losses are amortized over a fixed 20-year period with a 5-year ramp up at the beginning of the amortization period. Non-investment gains or losses are amortized over a fixed 20-year period with no ramps. All changes in liability due to plan amendments (other than golden handshakes) are amortized over a 20-year period with no ramps. Changes in actuarial assumptions or changes in actuarial methodology are amortized over a 20-year period with no ramps. Changes in unfunded accrued liability due to a golden handshake are amortized over a period of five years. These changes will apply only to new unfunded accrued liability bases established on or after June 30, 2019.

The City's required contributions to CalPERS fluctuate each year and include a normal cost component and a component equal to an amortized amount of the unfunded liability. Many assumptions are used to estimate the ultimate liability of pensions and the contributions that will be required to meet those obligations. The CalPERS Board of Administration has adjusted and may in the future further adjust certain assumptions used in the CalPERS actuarial valuations, which adjustments may increase the City's required contributions to CalPERS in future years. One of the most significant factors used in determining the liability and the funding requirements is the rate of return that investments will yield prior to making payments, known as the discount rate. CalPERS approved an incremental reduction in the discount rate to be used in its actuarial valuation from 7.5% to 7.0% over the three Fiscal Years 2018-19 to 2020-21. The discount rate was automatically lowered in July 2021, from 7.0% to 6.8%, due to the CalPERS investment return for Fiscal Year 2020-21. Lower discount rates result in a comparative increase in the unfunded liability and the contributions required to meet those obligations. The City cannot provide any assurances that the City's required contributions to CalPERS in future years will not significantly increase (or otherwise vary) from any past or current projected levels of contributions.

The table below sets forth certain information regarding the electric utility's portion of the City's required contributions to its CalPERS Miscellaneous Plan for the Fiscal Years ended June 30, 2021 through June 30, 2025, which amounts were paid in full by the Electric System in each of such fiscal years.

City of Anaheim
Schedule of Electric Utility Pension Plan Contributions

Fiscal Year	Contribution Funded by Electric Utility	Actuarially Determined Contribution Amount by Electric Utility	Electric Utility Contribution Deficiency (Excess) to Actuarially Determined Contribution	Electric Utility Contribution as a % of Covered Payroll
2020-21	$11,089,000	$11,089,000	--	41.49%
2021-22	11,318,000	11,318,000	--	39.06
2022-23	11,925,000	11,925,000	--	43.28
2023-24	12,366,000	12,366,000	--	39.59
2024-25	13,791,000	13,791,000	--	40.44

Source: Anaheim.

Effective for the Fiscal Year ended June 30, 2015, the City adopted Governmental Accounting Standards Board ("GASB") Statement No. 68, affecting the reporting of pension liabilities for accounting purposes. Under GASB Statement No. 68, the City is required to report the Net Pension Liability (i.e., the difference between the Total Pension Liability and the Pension Plan's Net Position or market value of assets) in its financial statements.

The table below summarizes certain information relating to the electric utility fund's proportionate share of the Net Pension Liability of the City's Miscellaneous Plan for the measurement periods ended June 30, 2020 through June 30, 2024 (as reported in the City's electric utility fund audited financial statements as of the succeeding fiscal year). The electric utility's proportion of the Net Pension Liability was based on a projection of its long-term share of contributions to the pension plan relative to the projected contributions of all participating funds of the City.

City of Anaheim Electric Utility Fund
Proportionate Share of the Net Pension Liability – Miscellaneous Plan

Measurement Period(1)	Proportionate Share of the Net Pension Liability(2)	Electric Utility Share of the Net Pension Liability(2)	Net Position as a % of Share of Total Pension Liability	Share of Net Pension Liability as a % of Its Covered Payroll
2019-20	22.2428%	$98,035,000	71.16%	344.91%
2020-21	22.6166	58,177,000	83.58	200.76
2021-22	21.9206	101,160,000	71.94	401.77
2022-23	21.4389	102,420,000	72.04	388.28
2023-24	21.5888	96,530,000	74.74	325.92

(1) Measured using prior fiscal year annual actuarial valuation rolled forward to measurement date.
(2) Reflects the electric utility's share of the City's Miscellaneous Plan Net Pension Liability of $440,748,000, $257,230,000, $461,482,000, $477,737,000 and $447,132,000 for the five Fiscal Year measurement periods of 2019-20, 2020-21, 2021-22, 2022-23 and 2023-24, respectively.
Source: Anaheim.

Retiree Health Benefits. In addition to the defined benefit pension plan described above, the City also maintains a program providing "other post-employment benefits" ("OPEB") to eligible retirees, including health care and disability coverage and death benefits. The City made significant changes to its OPEB program during Fiscal Year ended June 30, 2006. For City employees hired prior to January 1, 1996 (other than those represented by the Anaheim Police Association, the Anaheim Fire Association or the IBEW), the length of service credit was frozen for all employees eligible for the benefit. Length of service, a factor in determining the amount of the benefit earned, will not accrue beyond December 31, 2005. Employees hired on or after January 1, 1996 (other than those represented by the Anaheim Police Association or the Anaheim Fire Association) are no longer eligible for City funding of all or a portion of post-employment medical benefits. For City employees represented by the IBEW who had not retired as of October 15, 2005, medical benefits only for future retirees are to be provided through a trust established by the IBEW. Benefits are determined by the trustees of the trust and the City's liability is limited to specified percentages of employee pay.

City employees hired on or after January 1, 1996 and before January 1, 2002 (other than those represented by the Anaheim Police Association, the Anaheim Fire Association or the IBEW) were transitioned from the former defined benefit OPEB medical plan to a defined contribution OPEB medical plan. The City made a one-time contribution of $1,685,000 to a newly established retiree health savings account for those eligible employees. Participation in the retiree health savings account is mandatory for this transitional group of employees.

Based on eligibility status, retirees may participate in any health plan made available to active City employees. The City has several plans with different contribution levels and benefit provisions. The City's contributions vary up to 100% of annual premium cost, depending on the employee's Medicare eligibility, year of hire, age and employee group. At June 30, 2025, 1,337 retirees or surviving spouses met the various eligibility requirements and were receiving medical benefits.

The City's contributions toward the cost of its OPEB program are generally advance funded on an actuarial basis to a dedicated reserve, but annual contributions are not required. To pre-fund OPEB liabilities, the City participates in the California Employers' Retiree Benefit Trust, an agent multiple employer plan consisting of an aggregation of single-employer plans, with pooled administrative and investment functions that are administered by CalPERS. As of the actuarial valuation date of June 30, 2023, the unfunded liability for the City's Post-Employment Medical Benefits Program was $101,950 or 50% funded.

For Fiscal Years prior to Fiscal Year 2017-18, the City's reported annual OPEB cost (expense) was determined in accordance with the parameters of GASB Statement No. 45. The electric utility paid its allocated share of the City's annual full cost for current premiums.

Effective for Fiscal Year 2017-18, the City follows the provisions of GASB Statement No. 75, Accounting and Financial Reporting for Postemployment Benefits Other Than Pensions ("GASB No. 75") affecting the reporting of OPEB liabilities for accounting purposes. GASB No. 75 replaces the requirements of GASB Statement No. 45. GASB No. 75 establishes standards for employers with other postemployment liabilities for recognizing and measuring net OPEB liabilities, along with deferred inflows and outflows of resources, and expenses/expenditures related to the other postemployment liability. GASB No. 75 does not establish requirements for funding.

City contributions to the OPEB Plan occur as benefits are paid to retirees or contributions to the OPEB Trust. The City contributes an amount not less than the annual actuarially determined contribution measured in accordance with the parameters of GASB No. 75. The table below sets forth certain information regarding the electric utility's allocated share of the City's annual contributions to the OPEB Plan for the Fiscal Years ended June 30, 2021 through June 30, 2025, including the relation of such contributions to the actuarially determined contribution amount for such fiscal year.

City of Anaheim
Schedule of Electric Utility OPEB Plan Contributions

Fiscal Year	Contribution Funded by Electric Utility	Actuarially Determined Contribution Amount by Electric Utility	Electric Utility Contribution Deficiency (Excess) to Actuarially Determined Contribution	Electric Utility Contribution as a % of Covered Payroll
2020-21	$2,049,000	$1,773,000	(276,000)	8.04%
2021-22	1,970,000	1,781,000	(189,000)	7.61
2022-23	1,774,000	1,774,000	--	6.48
2023-24	1,863,000	1,863,000	--	6.09
2024-25	1,663,000	1,663,000	--	5.44

Source: Anaheim.

The table below summarizes certain information relating to the electric utility fund's proportionate share of the City Net OPEB Liability for the measurement periods ended June 30, 2020 through June 30, 2024 (as reported in Anaheim's electric utility fund audited financial statements as of the succeeding fiscal year).

City of Anaheim Electric Utility Fund
Proportionate Share of the Net OPEB Liability

Measurement Period[(1)]	Proportionate Share of the Net OPEB Liability[(2)]	Electric Utility Share of the Net OPEB Liability[(2)]	Net Position as a % of Share of Total OPEB Liability	Share of Net OPEB Liability as a % of Its Covered Payroll
2019-20	13.0617%	$20,912,000	37.91%	76.36%
2020-21	12.5016	13,395,000	53.77	52.59
2021-22	12.2649	15,052,000	46.79	58.12
2022-23	12.0136	13,800,000	50.04	50.41
2023-24	12.2419	12,481,000	55.59	40.80

(1) Measured using actuarial valuation as of the measurement date.
(2) Reflects the electric utility's share of the City's Net OPEB Liability of $160,100,000, $107,149,000, $122,722,000, $114,869,000 and $101,950,000 for the fiscal year measurement periods of 2019-20, 2020-21, 2021-22, 2022-23 and 2023-24, respectively.

Source: Anaheim.

Additional information regarding the City's retirement plans and OPEB, including information regarding the assumptions used to determine the pension and OPEB liabilities and the funding requirements therefor, can be found in Notes 10 and 11 and the Required Supplementary Information to the City's audited financial statements included in the City's annual comprehensive financial report, which may be obtained on the Electronic Municipal Market Access website of the Municipal Securities Rulemaking Board, currently located at http://emma.msrb org.

Litigation Affecting the Electric System

General. At any given time, the City has pending against it a number of claims and lawsuits arising out of matters usually incidental to the operation of a utility such as the Electric System. The City is of the view that, if determined adversely to the City, the actual damage awards likely to be ultimately paid with respect to any such current claims and lawsuits would not, in the aggregate, materially impair the City's ability to pay its Electric System obligations.

In addition, there are various ongoing proceedings to which the City is not a party that involve projects in which the City has an interest and which comprise a portion of the current resource portfolio of the Electric System; although the City is not a party to these such proceedings, their outcome may impact the costs and operations of the affected project.

Federal Prosecution. On August 16, 2023, former Anaheim mayor, Harry Sidhu, agreed to plead guilty to four felony charges consisting of obstruction of justice, wire fraud, and two counts of making false statements to the Federal Bureau of Investigation ("FBI") and Federal Aviation Administration ("FAA"). In his plea agreement with federal prosecutors, Mr. Sidhu admitted that he sought to become a member of the City's negotiating team and provided confidential information related to the sale of Angel Stadium of Anaheim to people working for the Angels. On March 28, 2025, a United States District Court sentenced Mr. Sidhu to two months in prison, a year of supervised released, and a $55,000 fine for his crimes.