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

Relating to:

$81,100,000 Southern California Public Power Authority
Magnolia Power Project A, Refunding Revenue Bonds, 2020-1 (the "2020-1 Bonds")

and

$145,455,000 Southern California Public Power Authority
Magnolia Power Project A, Refunding Revenue Bonds, 2020-3 (the "2020-3 Bonds")

INTRODUCTION

This Annual Report is filed pursuant to Continuing Disclosure Resolutions (Resolution No. 2020-018 and Resolution No. 2020-019) adopted by the Southern California Public Power Authority (the "Authority" or "SCPPA") on March 19, 2020 (together, the "Disclosure Resolutions"), in accordance with Securities and Exchange Commission Rule 15c2-12 (the "Rule"). This Annual Report relates to the above-captioned bonds (together, the "Bonds"). The 2020-1 Bonds are described in the Authority's Official Statement dated April 15, 2020, and the 2020-3 Bonds are described in the Authority's Official Statement dated April 22, 2020, as supplemented by the Supplement dated April 20, 2021 to Official Statement dated April 22, 2020 and the Remarketing Memorandum dated March 30, 2023 (collectively, the "Official Statements"). Except as otherwise provided herein, terms used herein that are not defined herein have the meanings ascribed to such terms in the applicable Official Statement.

The information in this Annual Report is provided in order to comply with the Authority's contractual commitment established by the Disclosure Resolutions to provide certain of the information specified therein. Certain information in this Annual Report is not required to be provided by the Disclosure Resolutions. By providing such information, the Authority does not undertake or agree to provide such information in any future year. The Authority, the City of Anaheim, California ("Anaheim"), the City of Burbank, California ("Burbank") and the City of Glendale, California ("Glendale," and collectively with Anaheim and Burbank, the "Project A Participants" and, individually, a "Project A Participant") make no representation that this Annual Report contains all information material to a decision to purchase or sell any of the Bonds. Burbank is the Project Manager and Operating Agent for the Magnolia Power Project (the "Project").

The information set forth herein has been furnished by the Authority and the Project A Participants and includes information obtained from other sources, which are 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 Project A Participant or in the other matters described herein since the date as of which such information is provided.

THE MAGNOLIA POWER PROJECT

The Project consists of a combined cycle natural gas-fired power generating plant with a nominally rated net base capacity of 242 MW and appurtenant facilities located in Burbank. The Project is owned by the Authority and consists of a combustion turbine with steam injection, a heat recovery steam generator with supplemental duct firing, a selective catalytic reduction pollution control system, a steam turbine, two electric generators, control and administrative facilities, wet mechanical-draft cooling tower, a zero liquid discharge wastewater treatment system, two main step-up transformers and a gas-insulated substation at the existing Olive switchyard owned by Burbank. The General Electric Company provided the combustion turbine generator, the steam turbine generator and certain associated accessories and services. The Project utilizes dry low-NOx combustors with selective catalytic reduction for NOx control and an oxidizing catalyst for carbon monoxide control as required by the South Coast Air Quality Management District in order to meet best available control technology/lowest achievable emission rate requirements. The supplemental duct firing and steam injection systems increase the capacity of the generating plant to 310 MW of nominally rated net peaking capacity. The air permit for the Project limits the amount of annual emissions that the supplemental duct firing system may generate, thus limiting its use to approximately 1,000 hours annually.

On April 2, 2003, the Authority issued the Southern California Public Power Authority Magnolia Power Project A, Revenue Bonds, 2003-1 (the "2003 Bonds") to finance a portion of the costs of acquisition and construction of the Project. On July 11, 2006, the Authority issued bonds to finance certain costs of completion of the Project and Capital Improvements thereto and to provide for the replenishment of the Reserve and Contingency Fund. On June 13, 2007, the Authority issued a series of refunding bonds to refund a portion of the 2003 Bonds. On April 23, 2009, the Authority issued two series of refunding bonds (collectively, the "2009-1 Bonds" and the "2009-2 Bonds") to refund the bonds issued in 2007. On December 7, 2011, the Authority issued the Southern California Public Power Authority Magnolia Power Project A, Refunding Revenue Bonds, 2011-1 (the "2011 Bonds") to refund a portion of the 2003 Bonds. The final maturity of the bonds issued in 2006 occurred on July 1, 2016. On September 22, 2017, the Authority issued the Southern California Public Power Authority Magnolia Power Project A, Refunding Revenue Bonds, 2017-1 the (the "2017-1 Bonds") to refund the 2009-2 Bonds. On April 15, 2020 and April 22, 2020, the Authority issued the Southern California Public Power Authority Magnolia Power Project A, Refunding Revenue Bonds, 2020-1 (the "2020-1 Bonds") and the Southern California Public Power Authority Magnolia Power Project A, Refunding Revenue Bonds, 2020-3 (the "2020-3 Bonds"), respectively, to refund the 2009-1 Bonds and the 2017-1 Bonds. The final maturity of the 2011 Bonds occurred on July 1, 2022.

The Project commenced commercial operation on September 22, 2005, with a construction cost of approximately $255 million. This amount excludes approximately $37 million for allowance of funds used during construction and approximately $19 million for emission credits.

Operating Statistics

Set forth below are the operating statistics for the Project for fiscal years ended June 30, 2024 and June 30, 2025.

	Fiscal Year Ended June 30,	
	2024	**2025**
Gross Energy Generated (MWh)	1,570,963	1,344,833
Net Energy Generated (MWh)	1,512,625	1,295,648
Plant Capacity Factor[(1)]	71.8%	61.6%
Operating Availability[(2)]	96.4%	80.2%
Unit Heat Rate (BTU/kWh)[(3)]	7,798	7,690

(1) The Plant Capacity Factor is the ratio of the net energy generated to the output if it had operated at full nameplate capacity the entire time. It reflects the unit availability as well as the actual need for power produced by the unit.

(2) The Operating Availability is the ratio of hours in the period that the unit is capable of operating at some level to the number of hours in the period.

(3) The Unit Heat Rate is a measure of the efficiency of the unit and shows the amount of heat energy in BTU's necessary to produce 1.0 net kWh. The smaller this number is, the more efficient the unit.

Fuel Supply

The Project is fueled entirely by natural gas. The Southern California Gas Company (the "Gas Company") provides transportation of natural gas to the Project. Each Project A Participant has the right to deliver or cause to be delivered its share of natural gas to the Gas Company for redelivery to the Project. The Authority arranges for the purchase of natural gas for the Project when the Project's usage exceeds the amount of gas supplied by the Project A Participants. The Authority on behalf of the Project purchases natural gas at market prices under a multi-month agreement with a major international oil and gas producer.

From July 1, 2024 through June 30, 2025, the Project produced 1,295,648 MWh of energy (net) and used 9,962,984 MMBtu of natural gas, of which over 809,562 MMBtu of natural gas was purchased by the Authority on behalf of the Project. During this period, the average price of natural gas purchased by the Authority on behalf of the Project was $3.3185 per MMBtu. During this same period, the natural gas that was provided by the individual Project A Participants to the Project was acquired at prices unknown to the Authority.

The cost of natural gas has varied significantly during the past several years. The Authority is not able to determine what the future cost of natural gas will be for the Project. Each Project A Participant is responsible for supplying its share of the natural gas to the Project. Options include, but are not limited to, purchasing natural gas through a contract on a prepaid or "pay-as-you-go" basis, acquiring rights to physical natural gas, and using the Authority's existing arrangement to provide natural gas to the Project on behalf of Project A Participants.

All of the Project A Participants, along with the City of Colton, California ("Colton") and the City of Pasadena, California ("Pasadena," and collectively with the Project A Participants and Colton, the "Gas Projects Participants"), are participants in the Authority's Natural Gas Reserves Project. The Natural Gas Reserves Project consists of the Authority's leasehold interests in natural gas fields located in Wyoming and Texas. Financing for the capital costs of the entitlement shares purchased by Anaheim, Burbank and Colton in the Natural Gas Reserves Project was provided through the Authority's Natural Gas Project A revenue bonds. Glendale and Pasadena contributed capital to the Authority for the payment of their

respective shares of the capital costs of the Natural Gas Reserves Project. The Authority has sold the entire production capacity of its member-related leasehold interests in the Natural Gas Reserves Project, on a "take-or-pay" basis (with Glendale and Pasadena having no obligation to pay any debt service), through Gas Sales Agreements with the participants in the Natural Gas Reserves Project.

All of the Gas Projects Participants are also participants in the Authority's Prepaid Natural Gas Project. The Prepaid Natural Gas Project primarily consists of the acquisition by the Authority of the right to receive an aggregate amount of approximately 135 billion cubic feet of natural gas (which amount has been reduced to approximately 90 billion cubic feet as a result of a restructuring completed in 2009) from J. Aron & Company ("J. Aron") pursuant to the terms of five Prepaid Natural Gas Sales Agreements between the Authority and J. Aron, each relating to a separate participant in the Prepaid Natural Gas Project. The gas is delivered by J. Aron to the Authority at designated delivery points on the natural gas pipelines that serve the Prepaid Natural Gas Project participants in specified daily quantities each month over the approximately 30-year term (27-year term due to the restructuring) of each of the Prepaid Natural Gas Sales Agreements in exchange for the lump sum prepayment made to J. Aron by the Authority on the date of issuance of the Authority's Gas Project Revenue Bonds (Project No. 1) in 2007.

The Authority has sold 100% of its interest in the natural gas, on a "take and pay" basis, through gas supply agreements with Anaheim, Burbank, Colton, Glendale and Pasadena. As of December 31, 2025, $219,555,000 of such Prepaid Natural Gas Project Bonds were outstanding.

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ESTIMATED DEBT SERVICE REQUIREMENTS FOR THE BONDS

Year Ending July 1	2020-1 Bonds		2020-3 Bonds		Total[(2)]
	Principal	Interest	Principal	Interest[(1)]	
2026	$3,555,000	$3,296,250	$8,515,000	$3,815,298	$19,181,548
2027	3,835,000	3,118,500	8,870,000	3,548,761	19,372,261
2028	4,140,000	2,926,750	9,225,000	3,271,112	19,562,862
2029	4,465,000	2,719,750	9,605,000	2,982,350	19,772,100
2030	4,815,000	2,496,500	9,990,000	2,681,694	19,983,194
2031	5,180,000	2,255,750	10,400,000	2,368,987	20,204,737
2032	5,575,000	1,996,750	10,820,000	2,043,445	20,435,195
2033	5,985,000	1,718,000	11,260,000	1,704,757	20,667,757
2034	6,425,000	1,418,750	11,725,000	1,352,296	20,921,046
2035	6,895,000	1,097,500	12,205,000	985,280	21,182,780
2036	15,055,000	752,750	19,230,000	603,238	35,640,988
Total[(2)]	$65,925,000	$23,797,250	$121,845,000	$25,357,219	$236,924,469

(1) Assumes that the interest rate on the 2020-3 Bonds will be the rate of interest paid by the Authority under the associated Swaps (i.e., 3.125% per annum and 3.139% per annum).

(2) Totals may not add due to rounding.

Annual Operating Budget

Set forth below is a summary of the Project operating budget for the fiscal year ended June 30, 2025, the actual operating results for such fiscal year, and the operating budget for fiscal year ending June 30, 2026.

Description	FY 2025-26 Projected Operating Budget (in $000's)	FY 2024-25 Actual Operating Results (in $000's)	FY 2024-25 Projected Operating Budget (in $000's)
Authority Administrative and General Expenses	$1,164	$1,102	$1,152
Major Maintenance[(1)]	17,604	11,112	11,112
Operations and Maintenance Expenses	27,852	26,163	27,468
Capital Improvements	180	2,794	1,116
Fuel Transportation	8,232	8,319	9,048
Project A Gross Debt Service	19,884	18,794	19,608
Project A Interest Earnings	(1,200)	(2,729)	(2,640)
Project B Gross Debt Service	864	857	852
Project B Interest Earnings	(120)	(234)	(168)
Total Cost	$74,460	$66,178	$67,548

(1) Includes collection of funds for future major outages.

The foregoing operating budgets do not include the cost of fuel. See "THE MAGNOLIA POWER PROJECT – Fuel Supply."

Certain Financial Statements Relating to the Magnolia Power Project A

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

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Southern California Public Power Authority
Magnolia Power Project
Statement of Net Position
(In Thousands)

	Fiscal Year Ended June 30,	
	2025	**2024**
ASSETS		
Noncurrent assets		
Net utility plant	$111,479	$117,229
Net lease asset	2,788	3,053
Investments - restricted	35,382	48,632
Investments - unrestricted	19,395	-
Fair value of derivative instruments	635	1,794
Total noncurrent assets	169,679	170,708
Current assets		
Cash and cash equivalents - restricted	8,370	17,141
Cash and cash equivalents - unrestricted	4,157	23,760
Interest receivable	212	270
Accounts receivable	293	195
Materials and supplies	11,887	11,737
Prepaid and other assets	613	42
Total current assets	25,532	53,145
DEFERRED OUTFLOWS OF RESOURCES		
Unamortized loss of refunding	7,121	8,440
Accumulated decrease in fair value of hedging derivatives	730	87
Total deferred outflows of resources	7,851	8,527
Total assets and deferred outflows of resources	$203,062	$232,380
LIABILITIES		
Noncurrent liabilities		
Long-term debt	$206,963	$220,755
Long-term lease liabilities	2,778	3,042
Fair value of derivative instruments	1,107	163
Notes payable and other liabilities	1,348	2,691
Total noncurrent liabilities	212,196	226,651
Current liabilities		
Debt due within one year	11,905	11,325
Current portion of long-term lease liabilities	264	250
Notes payable and other liabilities due within one year	13,954	34,358
Advances from participants due within one year	22,531	22,381
Accrued interest	5,710	5,298
Accounts payable and accruals	4,413	6,333
Total current liabilities	58,777	79,945
Total liabilities	270,973	306,596

NET POSITION		
Net investment in capital assets	(100,522)	(106,649)
Restricted	13,643	15,726
Unrestricted	18,968	16,707
Total net position	(67,911)	(74,216)
Total liabilities and net position	$203,062	$232,380

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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 the fiscal years ended June 30, 2025 and June 30, 2024.

Southern California Public Power Authority
Magnolia Power Project
Statement of Revenues, Expenses and Changes in Net Position
(In Thousands)

	Fiscal Year Ended June 30,	
	2025	**2024**
Operating revenues:		
Sale of electric energy	$117,130	$105,005
Total operating revenues	117,130	105,005
Operating expenses:		
Operations and maintenance	97,229	91,484
Depreciation, depletion, and amortization	8,810	9,475
Total operating expenses	106,039	100,959
Operating income (loss)	11,091	4,046
Non-operating revenues (expenses)		
Investment and other income	2,689	3,939
Derivative gain (loss)	(1,460)	616
Other interest and debt expense	(6,015)	(7,014)
Net non-operating revenues (expenses)	(4,786)	(2,459)
Change in net position	6,305	1,587
Net position – beginning of year	(74,216)	(75,803)
Net position – end of year	$(67,911)	$(74,216)

FINANCIAL STATEMENTS

The audited financial statements of the Authority, Anaheim and Glendale for the fiscal year ended June 30, 2025 are attached hereto. The unaudited financial statements of Burbank for the fiscal year ended June 30, 2025 are attached hereto. The audited financial statements of Burbank for the fiscal year ended June 30, 2025 will be filed with the Municipal Securities Rulemaking Board's Electronic Municipal Market Access System for Municipal Securities disclosures once their audited financial statements are available to the public and the Authority.

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 Resolutions provide, 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 Resolutions. The Disclosure Resolutions further provide 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 applicable Disclosure Resolution which is set forth in Appendix E to each 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.

CITY OF BURBANK

The following is certain information concerning the City of Burbank ("Burbank" or the "City") and its electric system (the "Electric System"), prepared by Burbank for inclusion herein. This information does not purport to cover all aspects of the Electric System's business, operations and financial position. The June 30, 2025 information provided herein is preliminary and unaudited.

General

Burbank was incorporated as a general law city in 1911, adopted its City Charter in 1927, and is administered by a Council-Manager form of government. Burbank's estimated population as of January 1, 2025 was 106,146, according to the California Department of Finance. Burbank is located in the greater metropolitan Los Angeles area, approximately 12 miles northeast of the Los Angeles Civic Center complex. Burbank's Public Service Department was established in 1913 under the laws of the State of California to supervise the generation, purchase, distribution and sale of electricity and the purchase, distribution and sale of water. In 2000, the name of the Public Service Department was changed to Burbank Water and Power ("BWP"). BWP provides service to all electric and water customers within Burbank. Burbank owns and operates an integrated Electric System, which includes generation, transmission and distribution facilities, and a water system (the "Water System").

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.

For the Fiscal Year ended June 30, 2025, Burbank currently estimates the average number of customers of the Electric System was approximately 53,628 and the total megawatt hours ("MWh") of energy sold to customers throughout Burbank was approximately 961,401 MWhs.

Management

BWP is under the direct management of the BWP General Manager, subject to the policy and direction of the Burbank City Council and the Burbank Water and Power Board (the "BWP Board") and the broad administrative direction of the City Manager. The BWP Board consists of seven members appointed by the Burbank City Council. The BWP General Manager is responsible for policy and planning relating to the operation of both the Electric System and Water System. Legal services are provided by the City Attorney's office, and various administrative services are also provided by the City. Senior Management of the Electric System includes:

Mandip Samra, General Manager, holds a Bachelor of Arts in Economics from University of California, Los Angeles, a Master of Public Administration from The Maxwell School of Citizenship and Public Affairs at Syracuse University, and a Master of Urban Planning from the University of Southern California. Ms. Samra joined BWP in March 2021 and was promoted to General Manager in May 2024. She started her career as a Graduate Management Intern in the Customer Relations Division of Pasadena Water and Power in 2004. Prior to joining BWP, she worked in various management positions at Anaheim Public Utilities, Southern California Edison, and Pasadena Water and Power. Her experience in power supply ranges from regulatory compliance, managing the integrated resources plan, negotiating power resource contracts, representing the utility on various resource and transmission committees, and leading stakeholder engagement efforts as it relates to power supply.

Riad Sleiman, ***P.E., PMP***, Chief Assistant General Manager/Electric Services, holds a Bachelor of Science in Electrical Engineering from Loyola Marymount University and a Master of Business Administration from Woodbury University. Mr. Sleiman originally joined BWP in 2005 as an Electrical Engineering Assistant working on street lighting, major development reviews, project management, system

planning, development agreements and contract negotiations, advanced metering infrastructure deployment, and advanced grid analytics. He then worked on utility-scale battery storage, electric vehicle infrastructure planning, and deployment, implementing small cell policy and agreements, and introducing analytics and applications through the GIS and records group while at the City of Santa Clara electric utility (dba Silicon Valley Power). Mr. Sleiman rejoined BWP in 2021 as the Assistant General Manager/Electric Services. He is a licensed Electrical Engineer in the State of California and is a certified Project Management Professional.

Joseph Lillio, Chief Financial Officer ("CFO"), holds a Bachelor of Science in Business Administration with an option in accounting from California State University, Los Angeles and a Master of Public Administration with an option in public sector management and leadership from California State University, Northridge. Mr. Lillio joined BWP in May 2023. Mr. Lillio came to Burbank from the City of El Segundo where he served as the CFO for over seven years. Prior to that, he served in various leadership roles at the City of Oxnard, Las Virgenes Municipal Water District, City of San Fernando, and City of Santa Clarita. He has over 20 years of experience in municipal finance which includes water, wastewater, solid waste, and electric utilities. He also has seven years of private sector finance experience working in the corporate finance office for Princess Cruises.

Erik Olsen, Acting Assistant General Manager/Power Supply, holds a Bachelor of Science in Electrical Engineering from the University of California, Los Angeles. He is a registered Professional Engineer in the State of California with over 20 years of experience in the electric industry. Mr. Olsen joined BWP in June 2014 and has served in various roles, most recently as the Manager of the Energy Control Center and Principal Electrical Engineer in Electric Services for the Substation Engineering group. His career began as an Electrical Engineering Assistant with Glendale Water and Power in 2003, where he held several engineering and management positions. His expertise spans North American Electric Reliability Corporation (NERC) compliance, system planning, engineering, operations, and utility management.

Principal Facilities

The service area of the Electric System is solely within Burbank's boundaries, which encompasses 17.1 square miles. The principal facilities of the Electric System consist of two natural gas-fired steam electric generating units, one natural gas-fired combustion turbine electric generating unit, four microturbine electric generating units, four switching stations, 12 distributing stations, two customer stations and transmission and distribution lines aggregating approximately 411 circuit miles.

Power Distribution

Burbank interconnects its electric facilities with other electric utilities through an 806 million volt-amperes ("MVA") tie to the Los Angeles Department of Water and Power ("LADWP") at Receiving Station "E" as well as a 191-megawatt ("MW") tie with Glendale Water and Power. Presently, these ties have more than sufficient capacity to import enough power to meet Burbank's system load as well as to export power to the participants in the Magnolia Power Project. Burbank acts as the operating agent for the Magnolia Power Project and is responsible for operating the Magnolia Power Project on behalf of the Southern California Public Power Authority ("SCPPA" or the "Authority").

Within Burbank, bulk power is transformed from 69 kilovolts ("kV") to 34.5 kV by four switching stations interconnected with nearly 34 circuit miles of 69 kV lines. There are about 44 circuit miles of 34.5 kV lines that interconnect the switching stations with 12 distributing stations and two customer stations. Burbank has about 102 distribution circuits and 5,865 distribution transformers to serve residential neighborhoods and businesses. Burbank's distribution system includes about 136 distribution circuit miles of underground lines and 200 circuit miles of overhead lines.

(Burbank 2025 R. 15c2-12)

Insurance

Burbank is self-insured and self-administered for certain exposures through Risk Management & Safety, a division of the Management Services Department of the City. Burbank is self-insured for individual claims up to $2,000,000 for worker's compensation, and $1,000,000 for general liability. Since July 1, 2004, the City has been a member in Authority for California Cities Excess Liability (ACCEL), which is a risk sharing pool for municipal excess general liability. Each individual member self-insures all general liability losses for the first $1,000,000 and the members of the pool share losses between $1,000,000 and $10,000,000. The members jointly purchase additional layers of coverage beyond the pooled layer, with Burbank purchasing an additional $55,000,000 of excess coverage, for total coverage of $65,000,000. The layers of coverage above $10,000,000 are not pooled, but rather jointly purchased. The City self-insures its worker's compensation coverage for the first $2,000,000 of each loss, and the City purchases excess coverage up to statutory limits. The City charges the Electric Fund based upon the proportional payroll cost, job classification, and claim history. There have been no significant settlements or reductions in insurance coverage for the past three years. The City maintains a $10,000,000 flood insurance policy. The City does not currently maintain insurance coverage for the Electric System for earthquake or wildfire risks.

Power Supply - General

BWP currently meets its Electric System power requirements from a combination of on-site gas-fired generating facilities, power purchase agreements, firm contracts and non-firm energy purchases. Among such resources, Burbank purchases power from the Intermountain Power Project ("IPP") of the Intermountain Power Agency ("IPA"), the Hoover Uprating Project, Powerex Corp. for Portfolio Content Category 1 ("PCC 1") and 2 ("PCC 2") renewable energy, Tule Hydro for PCC 1 renewable energy and had a power exchange agreement with Morgan Stanley Capital Group Inc. ("Morgan Stanley"). PCC 1 is the highest quality renewable energy credit associated with renewable energy in the California Energy Commission's Renewable Portfolio Standards program. In order to count as PCC 1, the renewable energy must be produced in California (or directly delivered into a California balancing authority area), as produced, without any substitute energy from any other sources. PCC 2 is renewable energy credit associated with renewable energy generated outside of California and imported into the state in the California Energy Commission's Renewable Portfolio Standards program. It is a firmed/shaped energy product where the equivalent amount of energy from a non-renewable source is delivered to California and bundled with renewable energy credit. Additionally, through its membership in SCPPA, Burbank has entitlement interests in the Palo Verde Nuclear Generating Station ("PVNGS"), Milford Phase I Wind Project, Tieton Hydropower Project and Magnolia Power Project, and purchases power from the Copper Mountain Solar 3 Project, Don A. Campbell Geothermal Project, Ameresco Chiquita Canyon Landfill Gas Project, Pebble Springs Wind Project and Desert Harvest II Solar Project. See "On-Site Resources," "Non-Burbank Owned Resources" and "Renewable Energy Resources" below.

Certain of the projects in which Burbank has an entitlement interest or participation with other parties are 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 may ultimately be entitled to the capacity and/or output of the defaulting party's share of the project.

During the Fiscal Year ended June 30, 2025, the Electric System generated and purchased (exclusive of purchases and sales for wholesale purposes) approximately 1,009,790 MWh of electricity for delivery to customers throughout Burbank. The following table sets forth the amounts, in MWhs and

percentages, of electricity obtained by Burbank from its current resources for sales to customers throughout Burbank during the Fiscal Year ended June 30, 2025.

Burbank Water and Power
Annual Retail Electric Supply
Fiscal Year Ended June 30, 2025

Resource	MWh	Percentage
Renewables[(1)]	508,470	50.4%
Magnolia Power Project	100,970	10.0
Intermountain Power Project	174,050	17.2
Spot Purchases	161,970	16.0
Palo Verde Nuclear	34,380	3.4
Hoover Uprating	12,070	1.2
On-Site Generation	17,880	1.8
Total[(2)]	1,009,790	100.0%

(1) Renewable resources include the Milford Phase I Wind Project, Tieton Hydropower Project, Pebble Springs Wind Project, Ameresco Chiquita Canyon Landfill Gas Project, Copper Mountain Solar Project, Don A. Campbell Geothermal Project, Desert Harvest II Solar Project, Powerex Corp. purchase of renewable energy, spot renewable energy credits, local generation from BWP Valley Pumping Plant, local landfill microturbines, customer and utility solar installations, and an exchange agreement. See "– Renewable Energy Resources." For the Fiscal Year ended June 30, 2025, renewable energy resources made up approximately 52.9% of Burbank's total retail sales. This number differs from the official Renewable Portfolio Standard (RPS) calculation and compliance period, which are based on retail sales and calendar year.

(2) Does not equal total sales to customers throughout Burbank of approximately 961,401 MWh due to distribution losses and timing differences in billing cycles between sales to customers, purchased energy, and renewable energy credits. Totals may not add due to rounding.

Source: BWP.

[Remainder of page intentionally left blank.]

On-Site Resources

Burbank owns two steam electric generating units with a total combined net capacity of 99 MW (with a nameplate capacity of 109.7 MW), one combustion turbine electric generating unit with a total continuous net capacity of 48 MW (with a nameplate capacity of 60.5 MW), and four microturbine electric generating units with a total combined net capacity of 0.5 MW (with a nameplate capacity of 0.8 MW) as indicated in the following table:

On-Site Generation
Owned by Burbank Water and Power

Unit Name	Type	Nameplate Capacity (MW)	Continuous Capacity (MW)	Year In-service	Energy Produced in Fiscal Year 2024-25 (MWh)
Olive 1[(1)]	Steam	50.0	44.0	1959	0
Olive 2[(1)]	Steam	59.7	55.0	1964	0
Lake 1	Combustion Turbine	60.5	48.0	2002	12,066
Landfill	Microturbines	0.8	0.5	2020	4,155
Total		171.0	147.5		16,221

[(1)] Olive 1 and 2 were used as planning capacity and serve as backup or emergency generation capacity.
Source: BWP.

Non-Burbank Owned Resources

Burbank purchases power and transmission capability from other sources pursuant to contracts. These contracts provide generally for Burbank to pay costs associated with the firm purchase of power (including fixed components like operations, maintenance and administrative expenses as well as variable components like fuel expenses). With respect to each of the facilities discussed herein, Burbank is one of any number of purchasers of such power and, with the exception of Magnolia Power Project and the Tieton Hydropower Project, does not control the operations or management of such facility. See also "Indebtedness; Joint Powers Agency Obligations" below.

Intermountain Power Project. Until November of 2025, the IPP consisted of: (a) a two-unit coal-fired, steam-electric generating plant with net ratings of 900 MW per unit (the "Intermountain Generating Station") and 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 Project" below); (c) two 50-mile, 345 kV AC lines from the Switchyard to the Mona Substation in the vicinity of Mona, Utah, and a 144-mile, 230 kV AC transmission line from the Intermountain AC Switchyard to the Gonder Substation 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." As of November 26, 2025, the coal generators have been taken out of service and no longer operates for the IPP purchasers' needs. They have been replaced with two natural gas generators, and BWP no longer has coal in its resource portfolio.

IPP purchasers are 35 utilities (collectively, the "IPP Purchasers") consisting of Burbank and the California cities of Anaheim, Los Angeles, Riverside, Glendale and Pasadena (the "IPP California Participants"); the 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"). After June 2027, the cities of Anaheim, Riverside and Pasadena will not be part of the project. Pursuant to a construction management and operation agreement between IPA and 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 IPP Generation Station also represents Burbank's only source of electricity generated by coal-fired plants. The power purchase contract with IPA obligates Burbank 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 Burbank.

Transmission of the output from IPP to Burbank and the other IPP California Participants is provided by the STS. The STS was placed in operation in May 1987, and its current transfer capability is 2,400 MW. See "Transmission Resources – Southern Transmission Project" below. Burbank and SCPPA have entered into a transmission service contract to provide for transmission of Burbank's entitlement between the Generating Station and Adelanto. Transmission service from Adelanto to Burbank is provided under transmission service agreements with LADWP.

Senate Bill 1368 ("SB 1368"), which became effective in January 2007, prohibits any investment in baseload generation that does not meet specific emissions performance standards, subject to certain exceptions. In light of the restriction, the coal-powered generation facility has been replaced by combined cycle natural gas units (the "IPP Repowering Project"), which have reached Firm Operations as of December 4, 2025 and will allow for compliance with greenhouse gas emissions ("GHG") performance standards. The total cost of the IPP Repowering Project is estimated to be $4.96 billion. The IPP Repowering Project includes hydrogen betterments, gas pipeline, generation and decommissioning costs, and the STS Renewal Project (as defined and described in "– Transmission Resources – *Southern Transmission Renewal Project*"). Approximately half, or $2.5 billion, of the total IPP Repowering Project cost is for the STS Renewal Project, and the City's share of such cost is 4.22%. The City's share of the remaining estimated $2.46 billion IPP Repowering Project cost is 3.33%. The existing power sales contracts will terminate on June 15, 2027 and will be replaced by renewal power sales contracts ("IPA Renewal Power Sales Contracts") (which were executed in 2017) for the combined cycle natural gas units, which will continue for a term ending in 2077. The City will be obligated to pay for the capacity and energy purchased under its IPA Renewal Power Sales Contract on a "take-or-pay" basis as operating expenses of the Electric System, including principal of debt issued for the project, capital costs and costs related to operation and maintenance. See "– Indebtedness; Joint Powers Agency Obligations – *Joint Powers Agency Obligations*." Based on the most recent study (conducted in 2019) available to the City, the City expects that its proportionate share of the cost of decommissioning the coal-powered generation facility to be approximately $14 million. Pursuant to the provisions of the IPA Renewal Power Sales Contracts, the IPP participants also agreed to reduce the initially planned generation capacity for the repowered plant from 1,200 MW to 840 MW. Some of the power purchasers under the original power sales contracts will continue to be IPP participants under the IPA Renewal Power Sales Contracts. The cities of Anaheim, Riverside, and Pasadena will not be power purchasers under the IPA Renewal Power Sales Contracts. The City will take a smaller share of 28 MW generation capacity (3.334%) under the IPA Renewal Power Sales Contracts, and LADWP and the City of Glendale will both increase their respective generation shares. These units are capable of being powered by 30% green hydrogen, with an aim for 100% green hydrogen (i.e. hydrogen created solely by use of renewable energy) by 2045. Burbank has the option, however does not have the obligation, to become a hydrogen purchaser, and to participate in the use of hydrogen at the project. To date, Burbank has not participated in the production of hydrogen.

(Burbank 2025 R. 15c2-12)

IPA is working with participants to develop a plan to achieve the goal of reaching 100% green hydrogen fueled operation by 2045, pending the availability and the advancement of the required technology to reach those scales. IPA secured hydrogen storage facilities adjacent to the existing site. Such facilities use salt cavern storage capacity, along with energy conversion services. This provides the IPP participants the ability to convert renewable energy into green hydrogen to fuel the new generating units and is currently undergoing testing. LADWP is the only IPP participant that is required to purchase hydrogen under the conversion services agreement, however the City and Glendale each have the option to elect to become a hydrogen purchaser.

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 was to have ceased operation of the IPP coal units permanently. IPA now anticipates that the coal units will cease operation by December 2025. 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's obligation to provide the purchase option to the State with respect to one of the IPP coal-fired units remained, however. Utah H.B. 3004 also directed 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 directed environmental regulators in the State of Utah to determine whether such an application would be granted if submitted by IPA. The Utah Disposition Authority was also 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.

The Utah Disposition Authority submitted its air application with respect to the coal units by December 31, 2024, proposing to amend the provisions of IPA's existing permit that require the coal units to cease operation following commercial operation of the IPP natural gas units. The application contemplated operation of the natural gas units at 100% of their design capacity and operation of the coal units at a 60% capacity factor. In a letter dated January 22, 2025, the State of Utah reported to the Utah Disposition Authority that, if officially submitted by IPA, the State of Utah "could approve a similar application based on the information included" in the application submitted by the Utah Disposition Authority.

Prior to the enactment of H.B. 3004, IPA stated that Utah S.B. 161 purported to create obligations for IPA that were inconsistent with IPA's obligations under federal regulations and the IPP construction and operating permits issued under federal law; and that if IPA had complied with Utah S.B. 161, as originally enacted, IPA may have been subject to enforcement actions that could have resulted 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 have interfered 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. Pursuant to Utah S.B. 161, IPA did grant to the State of Utah an option to purchase the coal units and related assets specified in the bill. 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. The City cannot predict the impacts of this legislation on the operation of IPP or the construction and operation of the IPP Repowering Project.

(Burbank 2025 R. 15c2-12)

Although Utah law did not explicitly require IPA to submit such an application, in light of the Utah Legislature's stated intent to preserve the coal units for future operation, and demonstrated willingness to take action if IPA did not submit such an application, IPA submitted an application to amend its existing permit to construct the natural gas units as part of the IPP Repowering Project to allow the coal units to resume operation at a date after the natural gas units commence commercial operation. Utah House Bill 70 (discussed below) provides, however, that even after issuance of such an amended permit, the existing permit, including the requirement that the coal units cease operation and be placed in maintenance status, will remain in effect during the period that ends upon the earlier of when IPA sells the coal units or both (i) the resolution of all administrative and judicial challenges to the amended permit and (ii) the expiration of the applicable limitations period to file such challenges. Accordingly, IPA has indicated that it does not anticipate that the coal units will resume operation while IPA continues to own the coal units. In fact, Utah House Bill 70 relieves IPA of any obligation to commence operation of either coal unit during such period and contemplates that the Utah Energy Council, as established by that bill, will take title to and contract with a third party for the operation of one or both of the coal units.

On October 3, 2025, the Utah Department of Air Quality issued a permit to IPA that, in substance, approved IPA's amendment application. On October 31, 2025, Sierra Club and Healthy Environment Alliance of Utah filed an administrative appeal before the Utah Department of Environmental Quality challenging the issuance of the permit. IPA is a party to the appeal by operation of Utah law. Briefing on the matter will proceed through 2026. IPA is still assessing the potential impact of the appeal.

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.

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 Utah H.B. 70 and to identify the appropriate course of action in response to the recent enactments. These efforts are ongoing, and the City cannot predict the impacts of the new legislation on the operation of IPP or the construction and operation of the IPP Repowering Project.

Hoover Uprating Project. Burbank is a participant in the Hoover Uprating Project, consisting primarily of the uprating of the 17 generating units at the hydroelectric power plant of the Hoover Dam.
(Burbank 2025 R. 15c2-12)

Burbank has a 0.98% (20.325 MW) entitlement interest in the total capacity and allocated energy of Hoover. Burbank has executed a power sales contract and has agreed to make monthly payments in exchange for its share of Hoover capacity and allocated energy, which contract expires in 2067. The region where Hoover Dam and its hydroelectric facilities are located has been experiencing drought conditions for approximately 20 years. Hoover Dam can generate power when Lake Mead level is above 950 ft above sea level or higher. The operation of Hoover Dam is expected to continue until Lake Mead drops below the 950 ft minimum or additional water sources are available from upstream sources.

Palo Verde Nuclear Generating Station (PVNGS). Through its membership in SCPPA, Burbank has a 4.40% entitlement interest (9.7 MW) in SCPPA's 5.91% ownership interest in PVNGS, including certain associated facilities and contractual rights, a 5.44% ownership in the Arizona Nuclear Power Project ("ANPP") High Voltage Switchyard and associated contractual rights, and a 6.55% share of the rights to use certain portions of the ANPP Valley Transmission System. Commercial operation and initial deliveries from PVNGS Units 1 and 2 commenced in 1986 and Unit 3 commenced in 1987. Transmission for PVNGS energy is provided to Burbank by the Mead-Adelanto Transmission Project and the Mead-Phoenix Transmission Project (see "Transmission Resources" below) and agreements with Salt River Project, LADWP and Southern California Edison Company.

Burbank has a power sales agreement with SCPPA which obligates Burbank to pay for its share of capacity and energy on a "take-or-pay" basis, including debt service on bonds issued by SCPPA for the project, capital costs and costs related to operation and maintenance.

The co-owners of PVNGS have created external accounts for the decommissioning of PVNGS at the end of its life. Decommissioning is expected to begin between 2045-2047. Based on the most recent estimate of decommissioning costs, SCPPA has advised Burbank that its estimated share of decommissioning costs through SCPPA is approximately 94% funded. Burbank's obligation is 4.4% of the cost, or approximately $8.7 million, which is based on the most recent study that was conducted in 2019. No assurance can be given, however, that the amount accumulated to date will continue to be sufficient to fully fund SCPPA's share of decommissioning costs. SCPPA has advised Burbank that it anticipates it will receive a new estimate of decommissioning costs every three years.

Magnolia Power Project. Burbank is a participant and the operating agent of SCPPA's Magnolia Power Project, a 323 MW natural gas-fired combined-cycle electrical power generating facility. The Magnolia Power Project is located in the city of Burbank and is owned by SCPPA. The Magnolia Power Project was constructed and acquired for the primary purpose of providing participants in the Magnolia Power Project with firm capacity and energy to help meet their power and energy requirements. Burbank has a 30.9917% entitlement (75 MW base capacity and 97.6 MW peaking capacity) in the project through a long-term power purchase agreement with SCPPA which obligates the City to pay for its share of capacity and energy on a "take-or-pay" basis, including debt service on bonds issued by SCPPA for the project, capital costs and costs related to operation and maintenance.

Renewable Energy Resources

For the Fiscal Year ended June 30, 2025, the Electric System's renewable energy resources made up approximately 52.9% of its total retail sales. The Electric System is on track to meet the Renewables Portfolio Standard (RPS) of 46% for the calendar year 2025.

Burbank's renewable energy resources are described below.

Milford Wind Corridor Phase I Project. Burbank is a participant in SCPPA's Milford Wind Corridor Phase I Project, providing for the purchase over a 20-year term of all of the energy generated by a 203.5 MW nameplate capacity, wind-powered electric generating facility located near Milford, Utah.

Burbank entered into a Power Sales Agreement with SCPPA for 5.0% (approximately 10 MW) of the output (including capacity, energy and associated environmental attributes) of the Milford Wind Corridor Phase I Project. The facility is owned by Milford Wind Corridor Phase I, LLC, a limited liability company organized and existing under the laws of the State of Delaware. The facility went into commercial operation on November 16, 2009. Burbank is able to accept the delivered facility energy utilizing its capacity rights in the IPP Switchyard that are provided under agreements relating to the IPP. The facility energy is then delivered over the STS to the Adelanto terminal in California utilizing Burbank's capacity rights in the STS. The facility energy delivered at Adelanto is then transmitted to Burbank under certain transmission arrangements between LADWP and Burbank.

Tieton Hydropower Project. Burbank is a participant in, and the operating agent of, SCPPA's Tieton Hydropower Project, a 13.6 MW nameplate capacity "run of the reservoir" hydroelectric generation facility located in the State of Washington. Burbank has entered into a power sales and acquisition contract with SCPPA, under which SCPPA has sold to Burbank on a "take-or-pay" basis, its entitlement of 50.0% (approximately 6.8 MW) of the capacity and energy of the Tieton Hydropower Project. Burbank's power sales and acquisition contract with SCPPA obligates Burbank to pay its share of debt service on bonds or notes issued by SCPPA for the project, as well as capital costs and costs related to operation and maintenance. Minor increases in the average annual and seasonal temperature in the Pacific Northwest are projected to continue as a result of global warming. However, projected changes in annual precipitation are expected to be very small. There has been no discernable impact to the project due to global warming to date. Tieton Hydropower Project averages about 48,000 MWhs of generation per year with slight annual variations attributable to year-to-year weather variations as well as changes in U.S. Bureau of Reclamation operations. For example, fish pulsing has had the greatest impact on water flow rates to the Tieton Hydropower Project.

Pebble Springs Wind Project. SCPPA, on behalf of three project participants, including Burbank, signed a long-term power purchase agreement with Pebble Springs Wind Project LLC for the purchase of the generating capacity of 98.7 MW (total capacity) wind project, comprised of 47 Suzlon 2.1 MW wind turbines. The facility is located in Oregon. Burbank has a 10.132% (approximately 10 MW) entitlement interest in the total capacity, energy and environmental attribute rights produced by the facility. The agreement expires on January 31, 2027.

Ameresco Chiquita Canyon Landfill Gas Project. Burbank entered into a power sales agreement with SCPPA for 16.7% (approximately 1.33 MW) of the output of Ameresco Chiquita Canyon Landfill Gas Project. The facility is developed, owned and operated by Ameresco Chiquita Energy, LLC in Chiquita Canyon Landfill in Valencia, California, near Highway 126 and west of Santa Clarita with a total capacity of 9.2 MW (gross), 7.8 MW (net). Burbank has an entitlement interest of 16.7% of the total capacity, energy and environmental attribute rights produced by the facility for 20 years. The plant began commercial operation on November 23, 2010. On February 22, 2024, SCPPA received a notice of force majeure due to a subsurface chemical reaction changing the hydrogen sulfide to dimethyl sulfide where the plant is not designed to treat or able to remove the substance, rendering it unable to operate in compliance with its air permit. The dimethyl sulfide overwhelms the gas treatment capacity of the plant. On October 16, 2024, SCPPA rejected the notice of force majeure and required that the plant owner make necessary upgrades to restore the plant to its historic quality and quantity.

Copper Mountain Solar 3 Project. SCPPA, on behalf of Burbank and LADWP, entered into a power purchase agreement for 250 MW of generating capacity of the Copper Mountain Solar 3 Project, located on the desert plains near Boulder City, Nevada. This energy is transferred to the Marketplace Switchyard, where the Mead-Adelanto transmission line runs to California. The commercial operation date for the project was declared on April 8, 2015. The agreement expires on April 9, 2035. Burbank has a 16.0% (approximately 40 MW) entitlement interest in the total capacity, energy and environmental attribute rights produced by the facility.

(Burbank 2025 R. 15c2-12)

Don A. Campbell I Geothermal Project. SCPPA, on behalf of Burbank and LADWP, entered into a power purchase agreement for 16 MW of net generating capacity of the Don A. Campbell I Geothermal Project located in Nevada. The commercial operation date for the project was declared on December 19, 2014. The agreement expires on January 1, 2034. Burbank has a 15.38% (approximately 3.845 MW) entitlement interest in the total capacity, energy and environmental attribute rights produced by the facility.

Valley Pumping Plant. In 2002, Burbank installed a small micro-hydro system to take advantage of a required pressure reduction where Burbank's water facilities interface with The Metropolitan Water District of Southern California ("MWD") at the Valley Pumping Plant. Peak output of the facility is approximately 550 kilowatts ("kW"). The micro-hydro system generates power when BWP purchases water from MWD.

Burbank Landfill Microturbines. The Burbank Landfill produces landfill gas ("LFG") that is collected to generate renewable power. Ten Capstone microturbines (of 30 kW capacity each) installed at the site in 2001 and one Ingersoll-Rand microturbine (of 250 kW capacity) installed in 2006 reached their end-of-life in 2014. The site was then repowered in 2020 using microturbines with 800 kW of new generating capacity. The LFG is reliable and sufficient to support 800 kW of power generating capacity. The equipment installed includes necessary gas pretreatment system that will effectively remove undesirable constituents such as moisture, volatile organics, hydrogen sulfide, and siloxanes from the LFG before it is combusted in the power generating equipment. The modernized control system also allows for remote monitoring and control of the operation.

Solar. Burbank has distributed generation in the form of behind the meter customer-owned rooftop solar photovoltaic (PV) systems throughout Burbank. As of June 2025, there were 2,030 residential and commercial owned solar PV systems in Burbank totaling more than 18 MW of capacity. Burbank expects that by 2026, there will be between 20 and 22 MW of cumulative capacity installed in Burbank with approximately 34,000 to 38,000 MWh of solar generation from customers annually.

Exchange Agreement. On August 3, 2016, Burbank and Morgan Stanley entered into an energy exchange agreement from April 1, 2017 to March 31, 2022. Under the agreement, Burbank will receive 23,500 PCC 1 qualified renewable energy and associated Renewable Energy Credits ("RECs") per year, 23,500 MWh of firm energy and PCC 2 qualified RECs per year, and 9,500 PCC 3 RECs per year. In exchange, Burbank will be obligated to deliver to Morgan Stanley approximately 131,400 MWh annually of firm energy at a rate of 15 MW per hour. On July 8, 2021, the City and Morgan Stanley entered into another energy exchange agreement from April 1, 2022 to June 30, 2025 for the same terms.

Desert Harvest II Solar Project. In December 2017, Burbank, along with the Cities of Anaheim and Vernon, entered into a power sales agreement with SCPPA for Desert Harvest Project. The Desert Harvest Project is located in Riverside County, California and began commercial operations in December 2020. Desert Harvest II Solar Project supplies energy and renewable attributes to SCPPA under a twenty-five-year REC + Index structure contract. The City contracted to purchase approximately 31.34% of its output.

Powerex Renewable Energy. In September 2022, Burbank and Powerex Corp. entered into a purchase agreement for 220,000 MWh bundled renewable energy with energy generated by projects and all associated green and environmental attributes. Under the agreement, Burbank will receive 20,000 MWh PCC 1 qualified renewable energy and associated RECs per calendar year. The contract will be effective from October 1, 2022 to September 30, 2032.

Tule Small Hydroelectric Project. Burbank and Tule Hydro LLC entered into a 15-year power purchase agreement for 6.4 MW of installed generating capacity located in Tulare County, California. The

project's commercial operation date was February 2025. The project is expected to deliver approximately 330,000 MWh of energy and PCC 1 RECs over the course of the contract.

Renewables 10-Year PCC 3. Burbank entered into two 10-year agreements to purchase PCC 3 from 3 Degrees Group, Inc. The contracts will deliver 70,000 PCC 3 RECs per annual for a total of 700,000 RECs and a total cost of $6.6 million. The PCC 3 certificates will contribute to the 60% RPS long term requirement and interim compliance period targets. The long-term requirement of the RPS regulation also requires 65% of all renewable contracts be at least 10 years or long in duration.

Battery Storage. In May 2024, Burbank commissioned its first long-duration energy storage (LDES) system, a 75 kW / 500 kWh ESS Energy Warehouse iron flow battery on Burbank 's EcoCampus. This system, integrated with a 265-kW solar array, will provide enough renewable power for 300 homes annually.

Fuel Supply

Fuel procurement for BWP's local generation units and the City's participation in the SCPPA Magnolia Power Project is addressed as part of its overall energy hedging strategy and undertaken in accordance with the BWP Energy Risk Management Policy. Fuel procurement instruments used include over the counter physical contracts, over the counter financial swap contracts, options, the SCPPA Natural Gas Reserves Project and the SCPPA Prepaid Natural Gas Project (described below), and biomethane contracts. Energy hedging decisions are continuously monitored and reviewed at the Risk Oversight Committee. See "Electric System Initiatives – *Wholesale Margins*" below for additional information about the Risk Oversight Committee. In August 2023, the California Public Utilities Commission (the "CPUC") approved an increase in the allowable storage at the Aliso Canyon facility. Prior to that decision, the use of Aliso Canyon Storage had been limited and protocols were in place that allowed for gas withdrawal to meet demand and ensure reliability of the electricity and natural gas systems. After the CPUC August 2023 approval to increase the allowable storage at the facility, the use of Aliso Canyon by Southern California Gas Company has been less restrictive and has helped to reduce volatility of spot natural gas prices. Thus far, there has been no adverse impact to the City relating to Aliso Canyon operations.

Natural Gas Reserves Project. Burbank is a participant in SCPPA's Natural Gas Reserves Project. The 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 and (ii) certain natural gas resources, reserves, fields, wells and related facilities in (or near) the Barnett Shale geological formation in Texas. Burbank has an interest in a portion of the production capacity of SCPPA's leasehold interests in the Natural Gas Reserves Project through a gas sales agreement with SCPPA, which agreement obligates Burbank to pay for its share of capital costs and costs related to operation and maintenance of the Natural Gas Reserves Project on a "take-or-pay" basis, as well as 100% of the debt service (on a several basis) on bonds issued by SCPPA to finance Burbank's share of the costs of development and acquisition of the Natural Gas Reserves Project.

Prepaid Natural Gas Project. Burbank 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, Burbank has entered into a natural gas supply agreement with SCPPA pursuant to which Burbank 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 the arrangement (as subsequently restructured) of approximately 27 years beginning on July 1, 2008.

Transmission Resources

Southern Transmission Project. The Southern Transmission System is owned by IPA and is one of the major components of IPP. Burbank is a participant in SCPPA's Southern Transmission Project, which provides Burbank with a 4.498% (currently 108 MW) entitlement in the transfer capability of the STS. Among other things, the STS provides for the transmission of energy from the IPP Generating Station to the California transmission grid. See "Power Supply-General – Non-Burbank Owned Resources – *Intermountain Power Project*" above. Burbank has a transmission service contract with SCPPA which obligates Burbank to pay its share of debt service on bonds issued by SCPPA for the project on a "take-or-pay" basis, as well as capital costs and costs related to operation and maintenance. 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.

Southern Transmission Renewal Project. As part of the IPP Repowering Project (see "– Non-Burbank Owned Resources – *Intermountain Power Project*"), SCPPA is financing the costs of acquisition and construction of additional capital improvements to the Southern Transmission System (the "STS Renewal Project"), which initially will include new converter stations and AC switchyard expansions at the Adelanto Converter Station and the Intermountain Converter Station, and reactive power equipment. The total cost of the STS Renewal Project is estimated to be $2.5 billion, and the City's share of such cost is 4.22%. The City has entered into a renewal transmission service contract related to the STS Renewal Project. Under such an existing agreement with IPP and such renewal transmission service contract the City is obligated to pay the cost of its share of the transfer capability on a "take-or-pay" basis, including principal of debt issued for the project, capital costs and costs related to operation and maintenance. See "– Indebtedness; Joint Powers Agency Obligations – *Joint Powers Agency Obligations*."

The IPA Renewal Power Sales Contracts provided a process for IPP members to subscribe for shares of the new gas-fired or alternative repowering plant. The Burbank City Council approved BWP's recommendation for continued participation in the IPP project which enabled the City to retain its share of the project. The City's share under the IPA Renewal Power Sales Contract is 4.222%, or 101.33 MW.

Mead-Phoenix Transmission Project, Authority Interest (Multiple Members). Burbank is a participant in SCPPA's member-related interest in the Mead-Phoenix Transmission Project, a 256 mile, 500-kV AC transmission line that extends between a southern terminus at the existing Westwing Substation (in the vicinity of Phoenix, Arizona) and a northern terminus at Marketplace Substation, a substation located approximately 17 miles southwest of Boulder City, Nevada. Burbank has entered into a transmission service contract with SCPPA under which SCPPA has sold to Burbank, on a "take-or-pay" basis, its entitlement share of 15.4% (approximately 35 MW) of the Authority's member-related ownership interest in the Mead-Phoenix Transmission Project and which obligates Burbank to pay its share of capital costs and costs related to operation and maintenance.

Mead-Adelanto Transmission Project, Authority Interest (Multiple Members). In connection with the Mead-Phoenix Transmission Project, Burbank has an 11.5337% (approximately 101 MW) entitlement to SCPPA's member-related interest in the Mead-Adelanto Transmission Project, an approximately 202-mile, 500-kV AC transmission line that extends between a southwest terminus at the existing Adelanto Substation in southern California and a northeast terminus at Marketplace Substation, a substation located approximately 17 miles southwest of Boulder City, Nevada. Burbank has entered into a transmission service contract with SCPPA, under which SCPPA has sold to Burbank, on a "take-or-pay" basis, its entitlement of SCPPA's member-related ownership interest in the Mead-Adelanto Transmission Project. Burbank's transmission service contract with SCPPA obligates Burbank to pay its share of capital costs and costs related to operation and maintenance.

Pacific Northwest-Pacific Southwest 500 kV DC Transmission Line. The DC Intertie is an 850 mile ± 500 kV DC line rated 3,100 MW connecting the Pacific Northwest with the Los Angeles Basin. The line is operated by both LADWP and Bonneville Power Administration ("BPA"). LADWP operates the southern section and BPA operates the northern section. Burbank and the cities of Glendale and Pasadena participated in the Sylmar Expansion Project which was completed in 1991 and which provided a 1,100 MW expansion (from 2,000 MW to 3,100 MW) of the DC Intertie's AC/DC terminal converter station located at Sylmar, California. Burbank has ownership in 119 MW of capacity at the Nevada-Oregon border. Burbank currently has excess capacity on this line.

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Customers and Energy Sales

The following table sets forth the electric revenues derived by Burbank from sales by classification of services and peak demand during the five fiscal years shown.

Burbank Water and Power
Electric Revenues and Peak Demand
($000's)

	Fiscal Year Ended June 30,				
	2021	**2022**	**2023**	**2024**	**2025 (Unaudited)**
Electric Revenues from Sales:					
Residential	$45,553	$43,974	$48,931	$49,794	$59,217
Commercial[1]	39,435	42,876	46,242	48,736	52,872
Large Commercial[1]	58,345	60,875	66,082	67,060	69,047
Other Retail Revenues	6,513	6,578	4,161	7,861	10,855
Total Retail Revenues	$149,846	$154,304	$165,417	$173,453	$191,991
Wholesale	42,088[2]	21,486	40,324[2]	23,197[2]	22,452[2]
Other Operating Revenues[3]	9,040	6,600	7,146	6,962	16,035
Total Revenues[4]	$200,974	$182,390	$212,887	$203,612	$230,478
Peak Demand (MW)	292	246	290	263	309

(1) Declines in Fiscal Year ended June 30, 2021 are due primarily to the effects of the COVID-19 pandemic.

(2) Increase in Wholesale in Fiscal Year ended June 30, 2021 is due to higher demand during extreme weather events during the year. Increase in Wholesale in Fiscal Year ended June 30, 2023 is due to higher demand during extreme weather events and the resale of excess gas during the year. Decrease in Wholesale in Fiscal Year ended June 30, 2024, and Fiscal Year ended June 30, 2025, is due to less extreme weather events and the mild summer during the year. Wholesale uses excess assets to move energy outside of Burbank's retail system.

(3) Other operating revenues include transmission, telecommunications, intergovernmental, and other miscellaneous revenues. Other operating revenues do not include aid-in-construction.

(4) Totals may not add due to rounding.

Source: BWP.

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The following tables set forth the average number of retail customers and total retail energy sold during the past five fiscal years.

Burbank Water and Power
Average Number of Retail Customers

	Fiscal Year Ended June 30,				
	2021	**2022**	**2023**	**2024**	**2025**
Residential	46,152	46,290	46,688	46,155	46,658
Commercial	6,861	6,880	6,959	6,914	6,890
Large Commercial	84	82	82	84	80
Total	53,097	53,252	53,729	53,153	53,628

Source: BWP.

Burbank Water and Power
Total Retail Energy Sold
(Millions of kWh)

	Fiscal Year Ended June 30,				
	2021	**2022**	**2023**	**2024**	**2025**
Residential	287	275	286	259	275
Commercial	448	476	475	461	475
Large Commercial	227	228	232	223	211
Total	962	979	993	943	961

Source: BWP.

Largest Electric Customers

Burbank's five largest retail electric customers (excluding other City departments) accounted for approximately 17.04% of Burbank's energy sales for the Fiscal Year ended June 30, 2025. Burbank's ten largest retail electric customers (excluding other City departments), comprised of large commercial customers, accounted for approximately 22.26% of Burbank's energy sales for the Fiscal Year ended June 30, 2025, and Burbank's 25 largest retail electric customers (excluding other City departments), comprised of large commercial customers, accounted for approximately 31.38% of Burbank's energy sales for the Fiscal Year ended June 30, 2025.

Electric Rates and Charges

Per Burbank Municipal Code, the utility must remain self-supporting from a financial standpoint and requires rates sufficient to maintain its financial health. Because costs can change suddenly and materially, a regular review and report on rates is necessary. BWP regularly evaluates such information needed to maintain adequate rates and uses such information in its assessment of its rates. Electric rates are established by the Burbank City Council and are not subject to regulation by the CPUC or by any other state agency.

Although its rates are not subject to approval by any federal agency, Burbank is subject to certain provisions of the federal Public Utility Regulatory Policies Act of 1978 ("PURPA"). PURPA requires state regulatory authorities and nonregulated electric utilities, including Burbank, to consider certain rate-making standards and to make certain determinations in connection therewith. Burbank believes that it is operating in compliance with PURPA.

The Electric System's base rates have been changed ten times over the period beginning July 1, 2013. Burbank provides no free electric services. A 1.5% increase originally scheduled to take effect in July 2020 was postponed due to the COVID-19 pandemic. In May 2021, the Burbank City Council approved a 2.5% rate increase, spread out over two increases of 1.24% each effective October 1, 2021 and April 1, 2022. The rate increases were phased in to allow economic recovery from the COVID-19 pandemic for the community. In May 2022, the Burbank City Council approved a total overall increase of 6.0%, effective July 1, 2022. In June 2023, the Burbank City Council approved a total overall increase of 8.5%, which was effective July 1, 2023, and an overall rate increase of 8.0%, effective July 1, 2024. In May 2025, the Burbank City Council approved a total overall increase of 9.9%, effective January 1, 2026, and an overall rate increase of 9.9%, effective January 1, 2027.

Burbank Water and Power
Percentage Change in Electric Rates[(1)]

Effective Date	Overall System
07/01/13	1.75%
07/01/14	2.90
07/01/15	2.10
07/01/16	2.10
07/01/19	1.00
10/01/21	1.24
04/01/22	1.24
07/01/22[(2)]	6.00
07/01/23[(2)]	8.50
07/01/24	8.00
01/01/26	9.90
01/01/27	9.90

(1) Percentage change is based upon the immediately preceding rate.
(2) The increases effective July 1, 2022 and July 1, 2023 were higher than previous increases due to higher energy prices, investments in future sustainability, higher operating and maintenance expenses driven by inflation and supply chain issues.
Source: BWP.

The table below sets forth the weighted average billing price per kWh of Burbank's various retail customer classes for the five fiscal years shown.

Burbank Water and Power
Weighted Average Retail Billing Price[(1)]
(Cents per kWh)

	Fiscal Year Ended June 30,				
	2021	2022	2023	2024	2025
Residential	15.86	16.01	17.12	19.25	21.50
Commercial	16.02	16.21	17.30	18.51	19.83
Large Commercial	13.96	14.08	15.05	16.02	16.53
Weighted Average – All Classes Combined	15.49	15.66	16.72	18.12	19.58

(1) All weighted average rates exclude annual in-lieu transfers to the City's General Fund and street lighting transfers. City voters passed Measure T in June 2018 to continue a direct transfer of not more than 7% of BWP's gross annual sales of electricity to pay for City's essential services. See " – Transfers to the City's General Fund."
Source: BWP.

(Burbank 2025 R. 15c2-12)

Transfers to Burbank's General Fund

In accordance with the City Charter, the Burbank City Council has a long-standing practice of authorizing annual transfers from the Electric Enterprise Fund to the City's General Fund in the form of an in-lieu transfer of 5.0% and a street lighting transfer of 1.5% of the City's gross sales of electricity (exclusive of wholesale sales to other public or privately-owned utilities). The practice of transfer from the Electric Enterprise Fund to the General Fund was challenged by a plaintiff in a complaint filed in June 2016, *Christopher Matthew Spencer v. the City of Burbank* (Case Number: BS162779). In June 2018, the voters of Burbank passed Measure T, a ballot measure that amended the City of Burbank Charter to continue this practice of annual transfers from BWP's gross annual sales of electricity, paid by retail electric ratepayers. On October 30, 2018, the plaintiff and the City entered into a settlement agreement in connection with their dispute over these transfers. The City receives a 7% In-lieu of Taxes on electric retail revenues that is not reflected in the Electric Fund's financial statements. This amount for the year ended June 30, 2025 is Electric in-lieu of $10,378,720 and Street Lighting transfer of $2,830,497.

Historical Net Revenues and Statement of Net Position of the Electric System

The following two tables set forth (i) summaries of net revenues of the Electric System for the five fiscal years shown together with debt service coverage ratios with respect to BWP's Electric System revenue bonds and (ii) the statement of net position of BWP's Electric System for the five fiscal years shown.

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Burbank Water and Power
Historical Net Revenues and Debt Service Coverage
Electric System
($000's)

	Fiscal Year Ended June 30,				
	2021	**2022**	**2023**	**2024**	**2025 (Unaudited)**
Operating revenue:					
Retail	$149,846	$154,304	$165,417	$173,453	$191,991
Wholesale[1]	42,088	21,486	40,324	23,197	22,452
Other Operating Revenues[2]	9,040	6,600	7,146	6,962	16,035
Total Operating Revenue	$200,974	$182,390	$212,887	$203,612	$230,478
Operating expenses:					
Retail (Fuel, Purchased Power and Power Operations)[3]	$93,250	$108,323	$119,701	$101,742	$123,879
Wholesale[1]	34,197	18,845	37,386	20,975	20,942
Other (Distribution and Other O&M)[4]	47,147	35,617	49,265	52,212	58,262
Optional advanced pension payment[5]	2,750	2,750	2,750	1,030	2,062
Total Operating Expenses[6]	$177,344	$165,535	$209,102	$175,959	$205,145
Operating income/(loss)	$23,630	$16,855	$3,785	$27,653	$25,333
Other non-operating income[7]	2,375	2,508	4,201	1,841	3,238
Net Income Available for Debt Service (a)	$26,005	$19,363	$7,986	$29,494	$28,571
Net Debt Service (b)[8]	$3,403	$3,403	$3,788	$10,412	$10,046
Rate Covenant Coverage (Prior to In-Lieu) (a) / (b)	7.64x	5.69x	2.11x	2.83x	2.84x
Revenues Available After Debt Service (a) – (b)	$22,602	$10,944	$4,198	$19,082	$18,525

(1) The increase in Wholesale in Fiscal Year 2020-21 is due to higher demand during extreme weather events during the year. Wholesale uses excess assets to move energy outside of Burbank's retail system. See "– Electric System Initiatives – Wholesale Margins."

(2) Other operating revenues include transmission, telecommunications, intergovernmental income, and other miscellaneous revenues.

(3) The increase in Retail Operating Expenses in Fiscal Year 2021-22 is primarily due to higher energy prices, coal supply issues at Intermountain Power Project, and one-time repairs for the Lake generating unit. The increase in Fiscal Year 2022-23 is primarily due to higher energy and gas prices, and the continued coal supply issues at Intermountain Power Project.

(4) The decrease in Other (Distribution and Other O&M) Operating expenses in Fiscal Year 2021-22 is primarily due to higher than expected CalPERS investment returns.

(5) During the Fiscal Year 2020-21 audit, the amount of optional advanced payment to CalPERS to reduce the City's unfunded actuarial liability for Fiscal Year 2019-20 and Fiscal Year 2020-21 was reclassified from non-operating expense to operating expense.

(6) Operating expenses exclude depreciation, in lieu of taxes, and interest expense.

(7) Other non-operating income includes interest income and other non-operating revenues, less other non-operating expenses. Other non-operating income does not include capital contributions, Build America Bonds subsidy, and non-cash adjustments to record market value adjustment for investment per Governmental Accounting Standards Board ("GASB") Statement No. 31 and market value adjustment for pension per GASB 68.

(8) Represents net debt service on outstanding bonds. Debt service on the Electric Revenue Bonds, Series of 2010B (Build America Bonds) (the "2010B Refunded Bonds") is net of the federal subsidy on the 2010B Refunded Bonds. Annual debt service beginning in Fiscal Year 2020-21 was much lower due to early redemption of the Electric Revenue Bonds, Series of 2010A. . In March 2023, the Electric System issued $120 million of fixed rate tax-exempt bonds to fund capital expenditures. The 2010B Refunded Bonds were redeemed in full with proceeds of the Electric Revenue Refunding Bonds, Series of 2024 on June 18, 2024.

Source: BWP.

Burbank Water and Power
Statement of Net Position
($000's)

	Fiscal Year Ended June 30,				
	2021	2022	2023	2024	2025 (Unaudited)
ASSETS					
Current and regulatory assets:					
Cash and cash equivalents	$85,228	$80,996	$180,142	$181,816	$182,294
Accounts receivable, net	21,974	16,875	26,276	20,442	20,169
Inventories	8,747	8,813	9,752	14,522	19,914
Derivative instruments	-	2,020	1,417	3,729	1,162
Deposits and prepaid expenses	17,104	16,164	17,493	17,402	18,224
Interest receivable	159	285	191	246	545
Leases Receivable	-	302	310	319	327
Due from the City of Burbank	-	284	299	310	276
Regulatory costs to be recovered in one year	14	-	-	-	-
Restricted nonpooled investments	-	-	-	-	-
Total current and regulatory assets[(1)]	133,226	125,739	235,880	238,786	242,911
Noncurrent and regulatory assets:					
Interfund receivable	6,450	-	-	-	-
Regulatory costs for future recovery	-	-	-	-	-
Leases receivables	-	4,557	4,247	3,929	3,601
OPEB assets[(1)]	-	2,450	2,007	2,814	3,413
Total noncurrent and regulatory assets	6,450	7,007	6,254	6,743	7,014
Capital assets:					
Land	2,734	2,734	2,734	2,734	2,734
Rights to purchase power	1,335	1,335	1,335	1,335	1,335
Utility plant and equipment	619,709	561,708	588,686	601,876	646,614
Machinery and Equipment	-	78,957	80,175	88,417	91,073
Leased Assets	-	1,779	1,779	1,151	1,309
Subscription Assets	-	-	1,718	2,529	1,886
Construction in progress	29,527	36,323	44,368	54,972	66,130
Total utility plant and equipment	653,305	682,836	720,796	753,014	811,081
Less accumulated depreciation	(339,915)	(361,212)	(381,583)	(394,814)	(416,615)
Net utility plant and equipment	313,390	321,624	339,213	358,200	394,466
Deferred outflows of resources:					
Deferred amounts from loss on bond refunding	-	-	-	-	2,588
Deferred amounts from pensions	14,001	10,925	33,119	29,789	17,908
Deferred amounts from OPEB	1,214	1,660	4,510	3,604	2,058
Total deferred from pensions and OPEB	15,215	12,585	37,629	33,393	22,554
Total assets & deferred outflows of resources	$468,282	$466,954	$618,975	$637,122	$666,945
LIABILITIES AND FUND EQUITY					
Current liabilities:					
Accounts payable and accrued expenses	$13,059	$12,630	$13,820	$12,256	$15,563
Bond interest payable	279	275	775	763	684
Lease liability	-	245	247	215	264
Subscription payable	-	-	477	786	454
Interfund payable	12	-	-	-	-
Customer deposits	8,535	16,427	20,869	30,780	57,023
Deferred revenue	-	548	47	46	-
Current portion of revenue bonds payable, net	1,145	-	2,210	2,295	4,140
Current portion of compensated absences	305	328	306	340	536
Total current liabilities	23,335	30,453	38,751	47,481	78,664
Noncurrent liabilities:					
Revenue bonds payable[(1)]	52,497	52,499	181,444	178,568	175,635
Compensated absences	6,922	6,688	7,207	8,054	8,314
Regulatory credits	327	302	208	1,106	836
Subscription payable	-	-	768	708	254
Lease liability	-	1,127	891	301	195
Net OPEB liability	3,766	-	5,098	2,730	1,808

(Burbank 2025 R. 15c2-12)

Net pension liability[2]	75,580	33,366	80,714	79,303	72,693
Total non-current and regulatory liabilities	139,092	93,982	276,331	270,770	259,735
Deferred inflows of resources:					
Deferred amounts on pensions and OPEB	2,864	36,229	5,765	6,399	4,640
Deferred amount from leases	-	4,859	4,557	4,087	3,731
Derivative Instruments[3]	-	2,020	1,417	3,729	1,162
Total deferred inflows of resources	2,864	43,108	11,739	14,215	9,533
Total liabilities and deferred inflows of resources	165,291	167,542	326,821	332,466	347,932
Fund equity:					
Total net position	302,991	299,412	292,154	304,656	319,013
Total liabilities and net assets	$468,282	$466,954	$618,975	$637,122	$666,945

[1] In Fiscal Year 2022-23, the City issued the Electric Revenue Bonds, Series of 2023 in the principal amount of $120,000,000 for capital improvement.

[2] Net pension liability was lower in Fiscal Year 2021-22 due to significantly higher investment returns. Investment returns were lower in Fiscal Year 2022-23 causing net pension liability to increase.

[3] In Fiscal Year 2021-22, the City implemented GASB Statement No. 53, "Accounting and Financial Reporting for Derivative Instruments" recording the fair value of the financial natural gas hedges.

Source: BWP.

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Capital Improvements

Burbank has a capital improvement program designed to meet load requirements, repair and replace facilities as needed, and satisfy new safety and regulatory requirements. All capital improvements are normally considered and adopted as part of Burbank's annual budget process, although additional capital expenditures may be approved as needed. Burbank currently expects to finance such capital improvements through a combination of bond financing, governmental grants and a "pay-as-you-go" basis.

The following table is a summary of Burbank's Five-Year Capital Improvement Program for the Electric System.

Burbank Water and Power
Five-Year Capital Improvement Program
($000's)

	2025-26 Adopted	2026-27 Forecast	2027-28 Forecast	2028-29 Forecast	2029-30 Forecast	Total Forecast
Power Supply Improvement Projects	$9,525	$2,775	$16,125	$950	$21,175	$50,550
Distribution Expansion Projects	20,344	6,042	11,059	16,138	7,569	61,152
Distribution Replacement Projects	32,668	28,308	28,246	18,338	19,085	126,645
New Customer Projects/AIC	56,285	7,050	11,242	15,178	10,750	100,505
Customer Service and others	6,906	2,213	4,469	3,092	1,925	18,605
Capital Outlay and other	7,992	7,098	11,945	11,046	8,943	47,024
Total CIP	$133,720	$53,486	$83,086	$64,742	$69,447	$404,481

Source: BWP.

Indebtedness; Joint Powers Agency Obligations

Electric System Revenue Bonds. As of December 31, 2025, Burbank has $164,055,000 in outstanding principal amount of long-term obligations payable from net revenues of the Electric System (after the payment of operating and maintenance expenses of the Electric System) consisting of $44,055,000 in outstanding principal of Electric Revenue Bonds, Series of 2024 Refunding bonds and $120,000,000 in outstanding principal of Electric Revenue Bonds, Series of 2023.

Joint Powers Agency Obligations. As described herein, Burbank contracts with IPA and SCPPA. Obligations of Burbank under the agreements with IPA and SCPPA constitute operating and maintenance expenses of the Electric System payable prior to any of the payments required to be made on Burbank's Electric System revenue bonds. Agreements between Burbank and IPA and Burbank and SCPPA (other than the agreement relating to SCPPA's Prepaid Natural Gas Project bonds) are on a "take-or-pay" basis, which requires payments to be made whether or not applicable projects are operating or operable, or whether the output from such projects is suspended, interfered with, reduced, curtailed or terminated in whole or in part. In addition, all of these agreements (other than the agreements relating to SCPPA's Prepaid Natural Gas Project bonds and the Natural Gas Reserves Project bonds) contain "step up" provisions obligating Burbank to pay its relevant share following a failure to pay by a defaulting participant. Burbank's participation and share of principal obligations (without giving effect to interest due on the obligations or any "step up" provisions) for each of the joint powers agency projects in which it participates are shown in the following table.

Outstanding Debt of Joint Powers Agencies and Burbank's Share
(as of December 1, 2025)

	Principal Amount of Outstanding Debt	City's Participation[1]	City's Share of Principal Amount of Outstanding Debt[2]
Intermountain Power Agency			
Intermountain Power Project (IPP)[3]	$112,520,000	4.021%	$4,524,429
IPP Renewal Project	1,695,130,000	3.334	56,515,634
Southern California Public Power Authority			
STS Project	72,190,000	4.498	3,247,106
STS Renewal Project[4]	1,790,705,000	4.222	75,603,565
Magnolia Power Project[5]	187,770,000	32.350	60,744,346
Milford Wind Corridor Phase I	52,835,000	5.000	2,641,750
Prepaid Natural Gas Project[6]	219,555,000	33.000	72,453,150
Natural Gas Project	7,255,000	100.000	7,255,000
Tieton Hydropower Project	26,585,000	50.000	13,292,500
Total	$4,164,545,000		$296,277,481

(1) Obligation is subject to increase upon default of another project participant (other than with respect to SCPPA's Prepaid Natural Gas Project bonds and the Natural Gas Project bonds).
(2) Excludes interest on the debt.
(3) Does include Burbank's share of the IPP excess power sales agreement.
(4) Until the effective date of the IPA Renewal Power Sales Contract, debt service will be based on the original transmission service contract. As a result, the City's share of outstanding debt is currently 4.498%, and upon the effective date of the IPA Renewal Power Sales Contract will be 4.222%. See "– Non-Burbank Owned Resources – Intermountain Power Project" and "– Transmission Resources – Southern Transmission Renewal Project." Subsequent to March 31, 2024, SCPPA issued $562,855,000 principal amount of bonds for the STS Renewal Project, of which the City's share is $21,901,633.
(5) Excludes bonds relating solely to City of Cerritos.
(6) The Prepaid Natural Gas Project is a "take-and-pay" contract. Payments by Burbank are contingent upon the delivery of gas.

Source: BWP; IPA.

For the Fiscal Year ended June 30, 2025, Burbank's payments of debt service on its joint powers agency obligations aggregated approximately $11.3 million. 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.

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Electric System Initiatives

Competitiveness Transition Plan. In 1998, the BWP Board and the Burbank City Council adopted, and has subsequently from time to time updated, its "Competitiveness Transition Plan" (as updated, the "Plan") in response to the then anticipated impacts of deregulation in California. Burbank has never granted open access for Burbank customers.

These goals have been adopted to fulfill the Plan:

- Maintain competitive and stable rates for all customer classes;
- Optimize use of assets, manage costs, and increase reserves;
- Maintain sound financial policies to ensure BWP's financial stability;
- Ensure that BWP is competitive with other Western utilities; and
- Uphold standards of customer service and reliability.

Power Supply Resources. The availability of local generation through existing facilities (the cost of which is more economic during periods of high cost in the power market) as well as the additional facilities utilizing state-of-the-art natural gas-fired technology (including the Lake 1 Unit and the Magnolia Power Project) are designed to allow Burbank to more efficiently dispatch local generation and to hedge against future market volatility in energy prices. In addition, utilizing local generation generally improves regional electric reliability because it does not depend on long-distance interstate transmission lines.

Burbank has taken the following actions to serve its customers and to mitigate the impact of recent changes in its power supply resource portfolio:

Integrated Resource Plan ("IRP"). The Burbank City Council approved the most recent IRP on December 5, 2023; the prior IRP was approved on December 11, 2018 and focused on decisions affecting coal-fired generation and the addition of cost-effective renewable energy in an environment of reduced load growth. The IRPs provide a long-term strategic framework for BWP's power supply portfolio, incorporating statewide policies, regional market conditions, and community priorities. Both IRPs recognized the need to plan for continued reductions in greenhouse gas emissions and outlined the City's strategy to meet Renewable Portfolio Standard (RPS) requirements.

Forward Purchases and Energy Risk Management. BWP has developed short-term as well as long-term energy procurement strategies to reduce price risks and volatility. These strategies are monitored by BWP management utilizing the Energy Risk Management Policy originally adopted in 2003 and last amended in 2022.

Renewable Energy. As described under "– Renewable Energy Resources" above, the Burbank City Council has adopted a RPS policy consistent with State law. For the Fiscal Year ended June 30, 2025, renewable energy resources made up approximately 52.9% of Burbank's total retail sales. Burbank is on track to meet the Renewables Portfolio Standard of 46% for calendar year 2025. As Burbank expects that the cost of renewable energy, relative to other energy options, may be greater, the acquisition of additional renewable resources may result in increased costs to Burbank and may require future rate increases, which are subject to Burbank City Council review and approval.

Wholesale Margins. Wholesale margins for the Fiscal Year ended June 30, 2025 were $1,510,000. Wholesale margins continue to contribute to Burbank's financial performance by reducing the utility's overall power supply costs. Wholesale trading opportunities exist because Burbank is able to market

BWP's excess capacity, energy or transmission. Burbank believes that wholesale transactions are low risk because they are short-term (*e.g.*, mostly less than 30 days), and not open-ended transactions. The trading risks are also mitigated through the adoption of the Energy Risk Management Policy, the formation of the Risk Oversight Committee ("ROC") and oversight by the Financial Planning and Risk Manager. The ROC meets regularly to review counterparty credits and transactions. Voting members of the ROC include the General Manager, Chief Financial Officer, Assistant General Manager/Power Supply, Energy Control Center Manager, Power Production Manager, Power Resource Manager, and Financial Planning and Risk Manager.

Financial Reserves. BWP management initially developed a financial reserve policy to maintain its long-term rate stability in 2003. The policy was last updated in 2023. Financial reserves are established for general operating expenses, debt repayment and capital funding, fleet replacement and general plant replacement. Under the financial reserve policy, BWP's updated financial reserve is based on available cash to fund normal operation per day or days cash on hand. Days cash on hand is calculated by taking the unrestricted cash and investments less depreciation and dividing by the annual operating expenses for one day. The financial reserve policy includes a minimum reserve and a recommended reserve. The approved minimum financial reserve for the Electric System is 105 days cash on hand and a recommended range between 160 to 240. The Electric System had 176 days cash on hand on June 30, 2025.

Customer Relations. As a community owned utility, BWP's relationship with its customers and community stakeholders continues to be an important focus. As the utility moves towards more renewable energy, which is intermittent in nature and as customers continue to electrify their transportation and homes, BWP will educate, engage, and work with customers to adopt beneficial electrification and to manage and shape load.

In late 2020, BWP's marketing group began pursuing an omni-channel marketing strategy with an emphasis on digital and social media channels to broaden its reach. This has resulted in greater opportunities for engagement with both residential and commercial customers about key issues such as COVID-19 relief, water conservation, and new EV rebate programs. Seventy-six percent of customers in the latest residential survey rated outbound communications as highly satisfactory, and BWP recently won two national awards from the American Public Power Association ("APPA"). APPA recognized BWP in print/digital and web/social media categories with Awards of Excellence. Burbank has maintained an outstanding system-wide reliability statistic. For Fiscal Year 2024-25, the system average interruption was only 12.03 (SAIDI) minutes per customer. A low frequency of outages helped minimize the system average outage duration. The Burbank outage frequency rate was approximately 0.32 (SAIFI) outages per customer every year.

Employee Relations

As of June 30, 2025, 273 full-time equivalent Burbank employees were assigned to the Electric System. Certain functions supporting the Electric System's operations, including but not limited to, meter reading, customer billing and collection, finance, administration, and operations technology are performed by BWP staff.

All BWP employees fall into one of four categories:

(1) Those represented by Local No. 18 of the International Brotherhood of Electrical Workers ("IBEW");

(2) Those represented by the Burbank City Employees' Association ("BCEA"), which is affiliated with the American Federation of State, County and Municipal Employees as Local No. 3143;

(3) Those represented by the Burbank Management Association ("BMA"); and

(4) Those that are unrepresented.

The BCEA, BMA and IBEW labor contracts are current. The BCEA labor contract will expire on June 30, 2026. The BMA labor contract will expire on June 30, 2028, and the IBEW labor contract will expire on June 30, 2027. Work will continue under the terms of the existing labor contract during negotiations pursuant to each labor contract until a new contract is in place.

There have been no strikes or other material work stoppages by Burbank employees within the last fifteen years.

Pension Plan and Other Post-Employment Employee Benefits for Employees of the Electric System

Pension Plan. Burbank's defined benefit pension plan, the Public Employees Retirement System ("PERS"), provides retirement and disability benefits, annual cost-of-living adjustments and death benefits to plan members and their beneficiaries. PERS is part of the Public Agency portion of the California Public Employees Retirement System ("CalPERS"), an agent multiple-employer plan administered by CalPERS, which acts as a common investment and administrative agent for participating public employers within the State of California. A menu of benefit provisions, as well as other requirements, is established by state statutes within the Public Employees' Retirement Law. Burbank selects optional benefit provisions from the benefit menu by contract with CalPERS and adopts those benefits through local ordinance. 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.*

Employees of the Electric System participate in Burbank's CalPERS Miscellaneous Plan. Burbank active plan members in the CalPERS Miscellaneous Plan hired prior to January 1, 2013, are required to contribute 8.00% to 9.14% 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 retirement system are required to contribute 7.50% of their annual covered salary. All Public Employees' Pension Reform Act members pay their full employee contribution. The City no longer pays for any employee contributions for any bargaining group.

Burbank is required to contribute the actuarially determined remaining amounts necessary to fund the benefits for its members. The actuarial methods and assumptions used are those adopted by the CalPERS Board of Administration. Burbank is required to contribute at an actuarially determined rate for the normal cost and a flat dollar amount for the required unfunded liability contribution. In Fiscal Year 2024-25, Burbank contributed 30.19% of annual covered payroll. The contribution requirements of plan members are established by state statute and the employer contribution rate is established and may be amended by CalPERS. The Electric System is allocated its portion of the required contributions. Approximately 34.74% of Burbank's CalPERS obligations are allocated to the Electric System. Burbank contributed 100% of the portion of the employer's actuarially required contribution allocable to the Electric System from the Electric Utility Fund for the Fiscal Years ending June 30, 2023, June 30, 2024, and June 30, 2025, in the amounts of $6,589,114, $5,770,282, and $6,613,596, respectively. Burbank has budgeted to contribute $7,909,688 as the Electric System's allocable share of the required contribution for Fiscal Years 2025-26. In addition to the annual required contribution, the Electric Utility Fund also made an additional voluntary lump sum payment of $2,062,200 to CalPERS to reduce the City's unfunded actuarial liability during Fiscal Year 2024-25. This payment was the second year of a two-year citywide funding plan that began in Fiscal Year 2023-24 to reduce future pension obligations. Burbank's Miscellaneous Plan had a funded ratio of 81.27% and 78.59% as of June 30, 2025, and 2024, respectively.

(Burbank 2025 R. 15c2-12)

In Fiscal Year 2014-15, Burbank implemented Governmental Accounting Standards Board (GASB) Statement No. 68, "Accounting and Financial Reporting for Pensions, an Amendment of GASB Statement No. 27" and GASB Statement No. 71, "Pension Transition for Contributions Made Subsequent to the Measurement Date, an Amendment of GASB Statement No. 68." These GASB Statements establish standards for measuring and recognizing liabilities, deferred outflows of resources, deferred inflows of resources, and expenses. For defined benefit pension plans, these GASB Statements identify the methods and assumptions that should be used to project benefit payments, discount projected benefit payments to their actuarial present value, and attribute that present value to periods of employee service. As of June 30, 2025, the proportionate share of Burbank's net pension liabilities allocable to the Electric System was reported to be $72,693,000 (measured as of June 30, 2024, and based upon a June 30, 2023, actuarial valuation rolled forward to June 30, 2024, using standard update procedures), a decrease of $6,610,000 over the prior fiscal year. The Electric System's proportionate share of the Net Pension Liabilities was 34.74% of the Net Pension Liabilities for Burbank's Miscellaneous Plan as a whole for Fiscal Year 2024-25. Reported deferred outflows of resources as of June 30, 2025 (to be recognized as a reduction of net pension liability in future periods) were $17,907,799 with reported deferred inflows of resources (to be recognized as pension expense in future periods) of $76. For the Fiscal Year ended June 30, 2025, Burbank's Miscellaneous Plan Net Pension Liability as a percentage of covered-employee payroll was 229.48%. The Miscellaneous Plan Net Pension Liability as a percentage of the Total Pension Liability for Burbank's Miscellaneous Plan was 81.27% for such Fiscal Year.

Post-Retirement Health Care Plans. Burbank also administers certain post-employment health care benefits under Burbank Employees Retiree Medical Trust ("BERMT"), the Utility Retiree Medical Trust ("URMT"), and the CalPERS Public Employees' Medical and Hospital Care Act ("PEMHCA") plan. The Electric System also makes contributions for such other post-employment benefits ("OPEB"). The Electric System assumes its share of OPEB costs based upon the results of actuarial studies. The City has pre-funded the PEMHCA and URMT plans through CalPERS OPEB Trust ("CERBT") and has a policy of contributing 100% of the City's actuarially determined contribution each year.

BERMT is a single employer, defined benefit plan which was established in April 2003 by Burbank's employee associations to provide post-retirement medical benefits to all non-safety employees, including elected and appointed officials. The trust is controlled by seven voting members from the various employee associations appointed to three-year terms. Burbank appoints an eighth member to the board, but that member is non-voting. Represented plan members are required to contribute $50 per bi-weekly pay period, which Burbank matches. Plan provisions and contribution requirements are established by and may be amended by the BERMT board. Investments are determined by the BERMT plan trustees and are governed by ERISA provisions. Eligibility for benefits requires that members are retired and have reached age 58 with a minimum of five years of contributions into the plan. The benefit provided ranges from $150 to $630 in reimbursements per month for eligible medical expenses. The Electric System has allocated its portion of the required contributions. For the Fiscal Year ended June 30, 2024, the allocable portion of Burbank's contributions to BERMT paid from the Electric Utility Fund totaled $364,495. For the Fiscal Year ended June 30, 2025, the allocable portion of Burbank's contributions to BERMT paid from the Electric Utility Fund totaled $371,950. The Electric Utility Fund has budgeted $368,223 for its share of contributions to BERMT in Fiscal Year 2025-26.

The PEMHCA Plan was established with CalPERS as a single employer plan. Burbank pays the required PEMHCA minimum contribution for all miscellaneous and safety employees retiring directly from Burbank. The Fiscal Year 2024-25 PEMHCA minimum contribution was $158.00 per month. In addition, Burbank paid $100.00 per month for 13 management retirees and paid $188.00 per month for nine IBEW retirees. For these management/IBEW retirees, the PEMHCA minimum required contribution of $158.00 is paid in addition to the retiree health contribution amounts. The PEMHCA benefit provisions are established and amended through negotiations between Burbank and its employee associations. For the Fiscal Year ended June 30, 2025, Burbank's annual determined contribution was $4,768,000 and the

allocable portion of Burbank's contributions to the PEMHCA plan paid from Electric Utility Fund totaled $939,296. As of June 30, 2025, the PEMHCA plan had a funded ratio of 84.66%.

Burbank also entered into an agreement on July 22, 2008, to provide certain OPEB to the IBEW employees, through the URMT, an agent multiple employer plan. The agreement is to supplement benefit payments from BERMT and PEMHCA for IBEW members and 12 management employees. The total target benefit is $1,200/month for individuals age 50 to age 64 and $750/month for those age 65 and above, with the exception that for qualifying employees who retire after December 16, 2015 and who have not contributed to Medicare while employed at Burbank and who are also not otherwise eligible for premium-free Medicare Part A at age 65 and older, the maximum amount at age 65 and older shall be $975/month, including payments from BERMT, PEMHCA minimum and the URMT. For the Fiscal Year ended June 30, 2025, Burbank's annual determined contribution was $39,000 and Burbank contributed $48,000 for the URMT. As of June 30, 2025, the URMT had a funded ratio of 129.03%.

In Fiscal Year 2017-18, Burbank implemented GASB Statement No. 75, "Accounting and Financial Reporting for Postemployment Benefit Other Than Pension Plans." This Statement replaces the requirements of Statements No. 45, "Accounting and Financial Reporting by Employers for Postemployment Benefits Other Than Pensions", as amended, and No. 57, "OPEB Measurements by Agent Employers and Agent Multiple-Employer Plans", for OPEB. This Statement establishes standards for recognizing and measuring liabilities, deferred outflows of resources, deferred inflows of resources, and expenses. For defined benefit OPEB, this Statement identifies the methods and assumptions that are required to be used to project benefit payments, discount projected benefit payments to their actuarial present value, and attribute that present value to periods of employee service. Note disclosure and required supplementary information requirements about defined benefit OPEB are also addressed. As of June 30, 2025, the proportionate share of Burbank's net OPEB liabilities allocable to the Electric System was $1,808.

Litigation

At any given time, there are certain claims and disputes, including those currently in litigation, that arise in the normal course of Burbank's Electric System enterprise activities. In the view of BWP management, based on consultation with the City Attorney, there is no litigation, present or pending, which will, individually or in the aggregate, materially impair Burbank's ability to service its Electric System indebtedness or which will have a material adverse effect on the business operations of the Electric System.

Future Developments

There has been increased development and service requests including large site developments, major housing developments, and accessory dwelling units during recent years and this trend is expected to continue in the years to come. In the last decade, BWP has energized about 400 new residential units. Based on the current proposed development, BWP is on the path to energize more than 2,000 new residential units in the next three to four years.

CITY OF GLENDALE

The following is certain information concerning the City of Glendale ("Glendale" or the "City") and its electric system (the "Electric System"), prepared by Glendale for inclusion herein. This information does not purport to cover all aspects of the Electric System's business, operations and financial position.

General Description

The City is a charter city of the State. The City Charter provides for the creation of major departments, including the Glendale Water and Power Department ("Glendale Water and Power" or "GWP") which is responsible for construction, maintenance and operation of all public utilities owned or operated by the City, including the Electric System and a water system (the "Water System"). The General Manager of Water and Power administers Glendale Water and Power under the authority of the City Manager and is charged with the operation of both the Electric System and the Water System.

Glendale Water and Power provides water and electricity to nearly all the residential, commercial and industrial customers within the 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.

Until 1937, Glendale purchased all of its electric energy from the Southern California Edison Company, successor to Pacific Light and Power Company, for distribution and sale to its customers. After the Boulder Canyon Project Act was approved by Congress in 1928, the City signed, in 1931, a contract with the United States for approximately 80,000 megawatt-hours ("MWh") of firm energy annually to be generated at the Hoover Dam. A contract was entered into at the same time with the City of Los Angeles to transmit this energy to Glendale at the maximum capacity of approximately 18 megawatts ("MW").

Studies made in 1938 showed that this firm allotment of Hoover Dam energy would not be sufficient for Glendale after 1942, with the result that Glendale established its own steam electric generating station located within the City, the Grayson Power Plant, with the first 20 MW unit being placed in service in 1941. This unit not only supplied energy to keep up with the growth of Glendale but also acted as standby to the transmission line from the Hoover Dam power plant. Since that time additional units owned by Glendale (and other resources) have supplied the energy requirements of Glendale.

The Electric System is interconnected with and in the Los Angeles Department of Water and Power Balancing Area. In 2024, the American Public Power Association recognized Glendale Water and Power as a Platinum Level Reliable Public Power Provider (RP3) for its service reliability, improvement programs, and safety performance.

The Electric System provides service to virtually all of the electric customers within the limits of Glendale, and has a service area of approximately 31 square miles and services an estimated population of approximately 192,212 as of January 1, 2025. For the Fiscal Year ended June 30, 2025, the customer base of the Electric System was comprised of approximately 78,071 residential customers, 13,458 commercial and industrial customers, and 21 other (governmental) customers.

Management of Glendale Water and Power

The Glendale City Council (the "City Council") has established the Glendale Water and Power Commission (the "Commission"), which is an advisory commission with the power and duty to make recommendations to the City Council: concerning (i) the operations and facilities of Glendale Water and Power and the need for changes or additions in its plant or in its operation; (ii) ways and means of financing

changes and additions to the plant or the methods of operation; and (iii) changes of administrative policy which the commission deems desirable in order that Glendale Water and Power may better serve the people of Glendale. In addition, the Commission serves as an appellate board with respect to cases concerning energy and water meter tampering and water backflow prevention devices. The Commission may also exercise such other powers and duties as may be prescribed by ordinance not inconsistent with the City Charter.

The Electric System is under the direct management of the General Manager of Glendale Water and Power. Senior Management of Glendale Water and Power includes:

Scott K. Mellon, P.E. General Manager of Glendale Water and Power. Mr. Mellon began his engineering career in aerospace developing electrical subsystems for multiple aircraft such as reusable launch vehicles, stealth drones, and lighter-than-air platforms. Inspired by what he learned about software-based control systems and the potential for such systems in a smarter future electric grid, he joined Burbank Water and Power (BWP) in 2001. Mr. Mellon spent most of his tenure at BWP as a Principal Electrical Engineer and Project Manager in the Power Supply division, most recently managing an Advanced Distribution Management System implementation. Joining GWP in September 2022 as the Assistant General Manager – Power Management, Mr. Mellon brings significant experience working with 24-hour operations staff maintaining grid stability, implementing utility-scale energy projects, and overseeing renewable energy contract negotiations which are critical to meeting Renewable Portfolio Standards and City Council goals for carbon neutrality. Mr. Mellon was appointed General Manager of GWP in June 2025. Mr. Mellon has a Bachelor of Science in Electrical Engineering (BSEE) from University of California, Irvine where he earned a Specialization in Power System Design and was a team lead on a Hybrid Electric Vehicle Project competition. He is a licensed Professional Engineer in the State of California (since 2001) and holds a Leadership certificate from Woodbury University.

Chisom Obegolu, Chief Assistant General Manager, Water Services. Chisom Obegolu is the Chief Assistant General Manager of Water Services. He is responsible for managing the water operational and business functions, which includes system operations, planning and water resources management. He oversees Water Engineering, Water Operation, Water Distribution, and Water Quality. Among his primary duties is to implement the water strategic plan and initiatives. Mr. Obegolu previously worked for Glendora Water where he served as the Assistant Director of Water Services. During his tenure at Glendora, he led a city-wide comprehensive water infrastructure assessment including an integrated water resources master plan and cost of service study. He also worked for The Metropolitan Water District of Southern California, where he served as the Lead Engineer on several critical capital improvement projects, and a number of infrastructure reliability initiatives. Mr. Obegolu is a registered Civil Engineer in the State of California and earned a bachelor's degree in Civil Engineering from The University of Texas at San Antonio and a master's degree in Public Administration from California State University, Northridge.

Daniel Scorza, Chief Assistant General Manager, Electric Services. Mr. Daniel Scorza joined Glendale Water and Power in 2019 as the Chief Assistant General Manager – Electric Services. He oversees the Electrical Engineering and the Electrical Transmission & Distribution Operations and Construction sections. Mr. Scorza previously worked for LADWP for 36 years, and during his last 10 years there, he served LADWP as a Power Engineering Manager. He comes to GWP with a wealth of experience in areas such as utility engineering and system studies, operations, maintenance, corporate finance, corporate training, legislative matters, and engineering services contracts. Mr. Scorza has a Bachelors in Science degree in Electrical Engineering (electronics) from California State University – Los Angeles ("CSULA"), a Masters in Electrical Engineering degree (telecommunications/computer systems) from CSULA, a Masters in Electrical Engineering degree with an emphasis in Power Systems from University of Southern California (USC), and a Master's in Business Administration from the USC. Mr. Scorza is a registered Professional Electrical Engineer in the State of California.

Adrine Isayan, Assistant General Manager, Utility Finance and Risk Management. Mrs. Isayan joined GWP management in February 2024. She was previously the Assistant Director of Finance for the City. She has 26 years of experience working for the City's Finance Department. Throughout her career, she has worked in various capacities within the Finance Department, with the majority of her experience being in the City's Budget, Accounts Payable, and Payroll sections. Mrs. Isayan has significant experience in the preparation of financial forecasting and reporting. She has a dual Bachelor's degree in Information Systems and in Finance, both from California State University, Northridge.

David Davis, Utility Finance Manager. Mr. Davis has over 37 years in accounting, financial reporting, management reporting and 25 years of progressively responsible, professional, broad-based electric and water utility experience. As Utility Finance Manager, he is charged with full management responsibility for financial reporting, budgeting and regulatory reporting for both Water and Electric utilities. Mr. Davis holds a Bachelor's degree in Accounting from the University of Akron. Additionally, Mr. Davis is a Certified Public Accountant licensed in the State of California.

Glendale Water and Power Governance

The City Council acts as the Board of Directors of Glendale Water and Power. The City Council consists of five members, who serve four-year terms. Elections are held every two years, with three members up for election in one cycle and two members up for election in the next cycle. The mayor is chosen annually from among the council members to serve as mayor. The City Council's authority consists of, but is not limited to, establishing rates, approving budgets and approving the hiring of senior management.

The current members of the City Council and their terms are:

	Current Term Began	Current Term Expires
Ara Najarian, Mayor	March 2022	April 2026
Ardy Kassakhian, Councilmember	April 2024	June 2028
Daniel Brotman, Councilmember	July 2022	June 2026
Elen Asatryan, Councilmember	July 2022	June 2026
Vartan Gharpetian, Councilmember	April 2024	April 2028

Principal Existing Facilities; Resources Generally

Glendale owns facilities for the distribution of electric power, including approximately 56 miles of 34/69-kV power lines, 503 miles of 4/12-kV distribution lines and 12 distribution substations.

Glendale maintains a diverse resource mix, with capacity available from natural gas, nuclear generating units, coal, large hydroelectric and a range of renewable resources, totaling 284 MW as of June 30, 2025. The Grayson Power Plant generating station, which is located within the City, has been in service since 1941. The Grayson Power Plant is currently under repowering, with all units except for Unit 9 being demolished. Unit 9, a simple cycle natural gas-fired combustion turbine with 50.5 MW of gross nameplate capacity, began commercial operation in 2003. It is used to meet intermediate and peaking loads, and provides ancillary services such as operating reserve capacity and load balancing as required.

In January 2023, the City Council approved Scholl Biogas Renewable Generation Project. The project is for the installation of four gas engine generators, along with a landfill gas cleanup system with the purpose of capturing and combusting the existing landfill gas to produce approximately 11 MW of renewable energy. The generator units were installed in December 2024 with substantial completion expected to be achieved in July 2026.

In February 2023, the City Council directed staff to implement the Grayson Repowering Project. The Grayson Repowering Project consists of, in part, new facilities that have a total capacity of approximately 56 MW (three reciprocating internal combustion engines rated at 18.6 MW each) (the "Wärtsilä Power Island") and a 75 MW/300 MWh battery energy storage system. All engineering, procurement, and construction contracts have been executed. The anticipated commercial operation for the battery energy storage system is the beginning of August 2026. The Wärtsilä Power Island is delayed due to late equipment deliveries and at this time its commercial operation date is the third or fourth quarter of 2026.

Although the Grayson Power Plant is the largest source of capacity, the majority of Glendale's energy requirements are supplied by various long-term power purchase agreements and spot purchases to minimize supply cost, improve reliability and comply with California's mandates, including the Renewable Portfolio Standards ("RPS") and the Cap-and-Trade Program. Glendale has met RPS requirements for Compliance Period 1 (2011-2013), and Compliance Period 2 (2014-16), and Compliance Period 3 (2017-20). Glendale Water and Power is currently on track to reach the targets for Compliance Period 4 (2021-24), as well as preparing to meet the new targets under SB 100 of 60% RPS by 2030 and 100% carbon-free by 2045. Glendale has entered into a contract through the Southern California Public Power Authority ("SCPPA") for the purchase of 10 MW of small hydroelectric in the Northwest. The hydroelectric contract converts to ownership by Glendale when the related bonds are fully paid. In 2007, Glendale secured 16 MW of wind-powered energy from the Pebble Springs project. This contract is set to expire in 2027. Glendale also has a 9.5 MW long-term contract for small hydroelectric power delivered from the Tieton Hydro Dam, which is set to expire in 2029. Additionally, this agreement will convert to City ownership once the associated bonds are fully repaid.

In 2015, Glendale entered into a 25-year 50 MW firm energy supply with Skylar Resource, L.P., of which 50% will be renewable; this arrangement was modified to ensure 55% of the energy is renewable beginning 2020, and an additional 20% of the energy is carbon-free beginning in 2020. Skylar Resources, L.P. assigned the power purchase agreement to Townsite Solar LLC in 2021. In 2020, Glendale entered into a contract for the purchase of 3 MW from the Whitegrass No. 1 geothermal project, and 12.5 MW from Starpeak geothermal, as well as 25 MW of Solar Energy and 18.75 MW/75 MWh of Battery Energy Storage System from Eland I Solar and Storage. See also "–Power Supply" below. The Whitegrass No. 1 Geothermal Energy Project (Whitegrass) is a 4.0 MW nameplate geothermal energy project located in Lyon County, Nevada. In the Whitegrass Project, the developer is currently in default due to not providing a replenishment of the required performance security. The City is currently considering its options in this matter. However, this contractual default in Whitegrass is not anticipated to have a material effect on the City's finances or operations.

Although available resources under contract or owned by the City are sufficient to meet the City's current daily loads, a portion of the Electric System's energy supply is purchased on the wholesale hourly, daily and month-ahead spot markets.

Glendale is also currently developing other programs related to electric demand and supply. In 2020, the City Council authorized a contract with Lime Energy Services Company (now Wildan Energy Co.) for a 36,500 MWh/8.32 MW commercial energy efficiency program. The program has delivered 28,000 MWh of savings (78% of program goal) and load reduction of 2.8 MW (35% of program goal) in

the first 3.5 years of the seven year program term. In November 2023, the City Council awarded two contracts for Phase 1 of the City Owned Solar Development Program. Motive Energy is currently conducting an environmental study for a ground mount solar project. Solar Optimum was awarded an Engineer, Procure, Construction contract for a rooftop or carport solar project on five sites. Total expected capacity for all six sites included in Phase 1 of the City Owned Solar Development Program is 4.9 MW. The GWP Perkins building roof top solar project was completed in March 2025 and the Central Library roof top solar project is scheduled for completion in December 2025. The Sports Complex and GWP's Utility Operations Center parking lot carpool solar projects are currently in the permitting process. The City continues to actively explore other local clean energy resources that can deliver energy, energy savings, storage and/or capacity to the City without utilizing GWP's transmission resources.

The following table sets forth the valuation of the Electric System facilities during the five Fiscal Years shown.

GLENDALE WATER AND POWER
ELECTRIC SYSTEM FACILITIES
($ in thousands)

	Fiscal Year Ended June 30,				
	2025	**2024**	**2023**	**2022**	**2021**
Utility Plant	$543,147	$539,734	$533,813	$615,413	$616,256
Less Accumulated Depreciation	(399,543)	(390,537)	(386,168)	(429,553)	(412,827)
Construction in Progress	418,945	162,863	29,695	9,086	8,075
Total Facilities	$562,549	$312,060	$177,340	$194,946	$211,504

Source: Glendale Water and Power.

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Power Supply

During the Fiscal Year ended June 30, 2025, the Electric System generated and purchased a total of 1,237,048 MWh. Sales to other utilities for the Fiscal Year ended June 30, 2025 were 104,008 MWh. Electric System peak demand in Fiscal Year ended June 30, 2025 was 348 MW. Over the five Fiscal Year period ended June 30, 2025, retail sales increased from 978,251 MWh to 993,009 MWh, an average annual increase of approximately 0.4%.

The following table sets forth the total power generated and purchased and the peak demand of the Electric System during the five Fiscal Years shown.

GLENDALE WATER AND POWER
TOTAL POWER GENERATED AND PURCHASED AND PEAK DEMAND

	Fiscal Year Ended June 30,				
	2025	**2024**	**2023**	**2022**	**2021**
Generated (MWh)	50,331	30,815	90,479	108,818	144,657
Purchased (MWh) [(1)]	1,186,717	1,219,048	1,392,077	1,371,399	1,410,514
Total Supply (MWh)	1,237,048	1,249,863	1,482,556	1,480,217	1,555,171
Retail Sales (MWh)	993,009	974,195	999,852	985,525	978,251
Sales to Other Utilities (MWh)[(1)]	104,008	224,585	397,991	419,063	482,809
System Peak Demand (MW)	348	287	329	261	335

[(1)] Fluctuations in purchased energy and sales to other utilities are a function of market conditions.
Source: Glendale Water and Power.

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The following table sets forth information concerning Glendale's power supply resources and the energy supplied by each during the Fiscal Year ended June 30, 2025.

GLENDALE WATER AND POWER
POWER SUPPLY RESOURCES
(as of June 30, 2025)

Source	Capacity Available (MW)	Actual Energy (MWh)[1]	Percent of Total Energy
Glendale-Owned Generating Facilities (Grayson):[2]			
Combustion Turbine Generators	50.5	50,331	4.07%
Joint Power Agency/Remote Ownership Interests:[3]			
Intermountain Power Project (IPA)	39	92,006	7.44%
Palo Verde Project	10	83,437	6.74%
Magnolia (SCPPA)	47	219,117	17.71%
Tieton (SCPPA)	7	7,572	0.61%
Purchased Power:[3]			
Hoover	20	46,531	3.76%
Pebble Springs Wind	20	41,093	3.32%
Skylar WSPP Renewables	50	289,482	23.40%
Star Peak	12.5	50,593	4.09%
Whitegrass No. 1	3	21,622	1.75%
Eland	25	68,791	5.56%
Market Purchases[4]	N/A	266,473	21.54%
Total	284	1,237,048	100.00%

(1) During the twelve-month period ended June 30, 2025.
(2) Rated or name-plate capacities. As of June 2024, the Grayson Power Plant is under repowering; all units were demolished, except for Unit 9.
(3) Entitlements, firm allocations and contract amounts.
(4) Market purchases are spot-market purchases.
Source: Glendale Water and Power.

Joint Powers Agency Resources/Remote Ownership Interests

As described below in various subsections, Glendale is a participant in many SCPPA projects. In addition, Glendale has long-term contract rights to capacity and energy in the Intermountain Power Project ("IPP") of the Intermountain Power Agency, a political subdivision of the State of Utah ("IPA") and in the Hoover Dam power plant, pursuant to contracts with the Western Area Power Administration ("Western"). See also "Indebtedness; Joint Powers Agency Obligations" below.

Certain of these projects in which Glendale has an entitlement interest or participation with other parties are 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 may ultimately be entitled to a portion of the capability and/or output of the defaulting party's share of the project.

These resources (including any sale and assignment of energy to another party, as described below under "–Indebtedness; Joint Power Agency Obligations – *Contingent Obligations for Wind Energy Projects*") are briefly described below.

Hoover Project Interest. Glendale is a contractor under Hoover Power Electric Service Contracts and holds an 18 MW share of the Hoover power capacity under Schedule A (referring to the original purchasers, including Glendale, under the Boulder Canyon Project Act of 1928), and a 2 MW share of capacity under Schedule B (referring to contractors, including Glendale, who advance-funded the Hoover power turbine uprating authorized in the 1984 Hoover Power Plant Act). The Hoover Project consists principally of 17 generating units at the hydroelectric power plant of the Hoover Dam, located approximately 25 miles from Las Vegas, Nevada. Modern insulation technology made it possible to "uprate" the nameplate capacity of existing generators (the "Hoover Uprating Project"). Glendale, along with the California cities of Anaheim, Azusa, Banning, Burbank, Colton, Pasadena, Riverside and Vernon obtained an entitlement to the capacity and allocated energy annually from the Hoover Uprating Project. In 1987, to reflect its entitlement, Glendale entered into contracts with the United States Bureau of Reclamation providing for the advancement of funds for the uprating and with Western for the purchase of power from the Hoover Uprating Project. Glendale is entitled to 20 MW or 1.0251% of the capacity and 1.5874% of the firm energy from the Hoover Project. Under normal hydrologic conditions, Glendale receives approximately 58,000 MWh of annual energy deliveries. In the Fiscal Year ended June 30, 2025, the Hoover Project provided 46,531 MWh of energy to Glendale.

The Electric Service Contracts for Hoover expired on September 30, 2017 and were replaced with new, 50-year Electric Service Contracts effective October 1, 2017. Pursuant to the Hoover Power Allocation Act of 2011, all Schedule A and Schedule B Hoover contractors, in each case including Glendale, have a right to continue to receive Hoover power for an additional term of 50 years, and five percent of Hoover's full rated capacity of 2.074 million kilowatts and associated firm energy was assigned to new Hoover allottees under new Electric Service Contracts that became effective on October 1, 2017. Glendale's share under the post-2017 Hoover Electric Service Contracts is 20.198 MW.

Palo Verde Nuclear Generating Station Interest. Through its membership in SCPPA, Glendale has a 4.40% entitlement interest (9.9 MW) in SCPPA's 5.91% ownership interest in the Palo Verde Nuclear Generating Station ("PVNGS"), including certain associated facilities and contractual rights, a 5.56% ownership in the Arizona Nuclear Power Project ("ANPP") High Voltage Switchyard and associated contractual rights, and a 6.55% share of the rights to use certain portions of the ANPP Valley Transmission System. Commercial operation and initial deliveries from PVNGS Units 1 and 2 commenced in 1986 and Unit 3 commenced in 1987. Transmission for PVNGS energy is provided to the City by the Mead-Adelanto Transmission Project and the Mead-Phoenix Transmission Project (see "Existing Transmission Resources" below) and agreements with Salt River Project, LADWP and Southern California Edison Company.

Glendale has a power sales agreement with SCPPA that obligates Glendale to pay for its share of capacity and energy on a "take-or-pay" basis, including debt service on bonds (if any, currently there are none) issued by SCPPA for the project, capital costs and costs related to operation and maintenance. In the Fiscal Year ended June 30, 2025, PVNGS provided 83,437 MWh of energy to Glendale.

The co-owners of PVNGS have created external accounts for the decommissioning of PVNGS at the end of its life. Based on the most recent estimate of decommissioning costs, SCPPA has advised Glendale that its estimated share of decommissioning costs through SCPPA is fully funded. No assurance can be given, however, that the amount accumulated to date will continue to be sufficient to fully fund SCPPA's share of decommissioning costs. SCPPA has advised Glendale that it anticipates it will receive a new estimate of decommissioning costs every three years.

San Juan Unit 3 Interest. Through its membership in SCPPA, Glendale has held a 20 MW (9.8%) entitlement in SCPPA's 41.8% interest in the San Juan Unit 3 and related common facilities of the San Juan Generating Station, a 4 unit, coal-fired electric generating station located in northwestern New Mexico, approximately 15 miles northwest of the City of Farmington, in San Juan County. As described below, Unit 3 was shut down on December 31, 2017, as part of an overall settlement of legal issues regarding emissions at the San Juan Generating Station.

In July 2015, with authorization from the City Council, SCPPA executed a San Juan Project Restructuring Agreement, a San Juan Decommissioning and Trust Funds Agreement and an Amended and Restated Mine Reclamation Agreement on behalf of Glendale and other SCPPA participants exiting from the San Juan project. These agreements allow for Glendale and certain other owners of the San Juan project to relinquish their ownership shares in San Juan and to contribute to the decommissioning and mine reclamation costs associated with the partial decommissioning of the coal plant. The agreements allow for the shutdown of two of the four San Juan units (Units 2 and 3) and provide for the installation of emissions-reducing equipment on the other two units (Units 1 and 4).

Glendale's and the other exiting parties' shares of the San Juan coal assets have been transferred to those participants remaining in the project after December 31, 2017. Glendale (through SCPPA) and other existing participants remain responsible for liability arising from operations before the December 31, 2017 date. Pursuant to the Mine Reclamation Agreement, SCPPA and the other project participants were obligated to set up a trust fund for the mine reclamation. Glendale's obligation after 2017 is defined by approximately 1.3% of the cost of reclaiming disturbances at the mine site as of December 31, 2017. Costs of plant decommissioning will be split between exiting participants and remaining participants.

Magnolia Power Project. Glendale is a participant of the Magnolia Power Project. The Magnolia Power Project is owned by SCPPA and was constructed and acquired for the primary purpose of providing participants in the Magnolia Power Project with firm capacity and energy to help meet their power and energy requirements. The Magnolia Power Project is operated by the City of Burbank. Glendale has a 16.5289% entitlement (40 MW base capacity and 47 MW peaking capacity) in the project through a long-term Project A Power Sales Agreement with SCPPA which obligates Glendale to pay for its share of capacity and energy on a "take-or-pay" basis, including debt service on bonds issued by SCPPA for the project, capital costs and costs related to operation and maintenance. The unit was placed in service in September 2005 and operates in a base-load mode (8,000 hours per year or more) with staffing by Burbank Water and Power personnel as SCPPA's operating agent on a 24-hour basis. In the Fiscal Year ended June 30, 2025, the Magnolia Project provided 219,117 MWh of energy to Glendale.

Tieton Hydropower Project. Glendale is a participant in SCPPA's Tieton Hydropower Project. Glendale has entered into a power sales and acquisition contract with SCPPA, under which SCPPA has sold to Glendale on a "take-or-pay" basis, its entitlement share of 50.0% (approximately 6.8 MW) of the capacity and energy of the Tieton Hydropower Project. Glendale's power sales and acquisition contract with SCPPA obligates Glendale to pay its share of debt service on bonds issued by SCPPA for the project, as well as capital costs and costs related to operation and maintenance. In the Fiscal Year ended June 30, 2025, the Tieton Hydropower Project provided 7,572 MWh of energy to Glendale.

IPA Intermountain Power Project Interest. The purpose of IPA is to provide for the financing, constructing and operation of the IPP. The IPP consists of: (a) a two-unit coal-fired, steam-electric generating plant with net ratings of 900 MW per unit (the "Intermountain Generating Station") and 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 "Existing Transmission Resources – *Southern Transmission System*" below); (c) two 50-mile, 345-kV AC lines from the Switchyard to the Mona Substation in the vicinity of Mona, Utah, and a 144-mile, 230-kV AC transmission line from the Intermountain AC Switchyard to the Gonder Substation 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."

IPP purchasers are 35 utilities consisting of Glendale and the California cities of Anaheim, Los Angeles, Riverside, Burbank and Pasadena; the 23 members of the IPA; and six rural electric cooperatives serving loads in the States of Utah, Arizona, Colorado, Nevada and Wyoming. Pursuant to a construction management and operation agreement between IPA and 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.

Glendale has entered into certain power purchase contracts with IPA and others to purchase certain entitlements of the IPP and related facilities, respectively. After accounting for transmission losses, for the Fiscal Year ended June 30, 2024, IPP contributed about 38 MW of capacity to Glendale. For the Fiscal Year ended June 30, 2025, IPP provided 92,006 MWh of energy to Glendale.

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.

IPP Agreements. Glendale has two separate contracts with IPA and the Utah Participants (as defined below) in the IPP, which currently provide Glendale a 38 MW (2.165%) entitlement of this facility (the "IPP Agreements"). A summary of the IPP Agreements is as follows:

Original Entitlement – Glendale contracted with IPA to purchase a 30 MW (1.704%) entitlement to the IPP plant. This contract obligates Glendale to pay its proportional share of the plant costs (including debt service and other fixed expenses), regardless of the amount of energy, if any, scheduled to Glendale, for the life of the facility.

Excess Power Sales Contract – Glendale, the cities of Burbank and Pasadena, and LADWP (the "California Purchasers") contracted with 27 sellers (the "Utah Participants") and IPA (acting as agent for the sellers) to purchase a 379 MW (21.06%) entitlement of the IPP plant, which was deemed in excess of the sellers' needs. The California Purchasers agreed to divide the excess

among themselves in proportion to their original entitlements. Glendale's share of the excess is 8 MW (2.382%). This contract also provides for access to the NTS, which was built with IPA funds in order to deliver power from the IPP to the Utah Participants. The term of this contract extends until the IPA bonds are defeased or the sellers' load requirements meet certain specified conditions. The Utah Participants have the unilateral right to recall their original entitlements at any time.

IPP Repowering Project. The above-referenced IPP Agreements expire in 2027, but one of the key factors affecting the future of IPP is 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 the restriction, in 2015, Glendale, along with each of the other 35 IPP participants, entered into Second Amendatory Power Sales Contracts, Renewal Power Sales Contracts, and Renewal Excess Power Sales Agreements with IPA. The Second Amendatory Power Sales Contract allows for the replacement of the coal-fired generation units at IPP with combined cycle natural gas-fired units (with a maximum design capacity of 1,200 MW), or an alternative repowering to include other technologies, if such alternative repowering is approved by at least 80 percent of the IPP participants (the "IPP Repowering Project"). In September of 2018, the IPP participants approved an alternative repowering project (the "IPP Alternative Repowering Project") which will reduce the size of the IPP Repowering Project to a maximum design capacity of 840 MW. The natural gas units were required to be permitted and commercially operational by July 1, 2025, though now projected to go into commercial service no later than December 2025. On November 5, 2019, the IPP Coordinating Committee adopted Resolution CC-2019-018, Confirmation of Commencement of Permitting, Construction and Installation of the Gas Repowering, confirming that the January 1, 2020 milestone has been met. Upon commercial operation of the new plant, the existing coal-fired plant would be decommissioned. SB 1368 and other recent legislation have caused Glendale to decrease its reliance on electricity generated by burning coal.

The Renewal Power Sales Contracts provided a process for IPP members to subscribe for shares of the new gas-fired or alternative repowering plant. On July 23, 2019, the City Council approved GWP's recommendation for continued participation in the IPP project which enabled Glendale to retain its 4.166% share of the project, providing Glendale 35 MW of generation and 122 MW of transmission from IPP. Glendale's current share of IPP generation provides approximately 7.4% of Glendale's energy needs.

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 its 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 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 of Utah 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 Utah H.B. 3004, IPA stated that Utah S.B. 161 would 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. 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. The City cannot predict the impacts of the new legislation on the operation of IPP or the construction and operation of the IPP repowering project.

During its 2025 General Session, the Utah Legislature enacted Utah House Bill 70 ("Utah H.B. 70"). Utah H.B. 70 was submitted to the governor of Utah and the bill became effective upon the earlier of May 7, 2025, and the governor's approval of the bill.

Utah H.B. 70 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.

Purchased Power

In addition to City-owned resources and interests in the SCPPA, IPA and Hoover projects described above, the City has contractual arrangements for system firm purchases, primarily from renewable resources. Each of these resources is briefly described below.

Pebble Springs Wind Project. SCPPA, on behalf of Glendale and two other project participants, signed a long-term power purchase agreement with Pebble Springs Wind Project LLC. The facility is located in Oregon with a total capacity of 99 MW, comprised of 47 Suzlon 2.1 MW wind turbines. Glendale has a 20.264% (approximately 20 MW) entitlement interest in the total capacity, energy and environmental attribute rights produced by the facility. In the Fiscal Year ended June 30, 2025, Pebble Springs Wind Project provided 41,093 MWh of energy to Glendale.

Skylar Resources Firmed Renewable Purchase. In 2014, Glendale executed a 25-year agreement with Skylar Resources L.P. for the annual delivery of 292,000 MWh of energy to Glendale starting on December 1, 2015. In the Fiscal Year ended June 30, 2025, 289,482 MWh of energy was delivered to

Glendale. Deliveries may take place at the Mead Substation, Nevada-Oregon Broader (NOB), or another mutually agreed point. At least half of this energy must qualify each year as Portfolio Content Category 1 ("PCC 1") renewable energy under State law and regulations, and may be generated from a variety of renewable resources. The energy is delivered to Glendale Water and Power as a block from 6 a.m. to 10 p.m. every day. In November 2015, the transaction was bifurcated into two separate agreements: the first agreement was a four-year contract with Morgan Stanley Capital Group, Inc. from December 1, 2015 through December 31, 2019. The second agreement was a 21-year contract with Skylar from January 1, 2020 through November 30, 2040. In October 2017 the existing power purchase agreement was terminated and replaced with a 21-year Western Systems Power Pool ("WSPP") Power Purchase Agreement to increase renewable and carbon-free energy deliveries from 50% to 75%. In 2021, Skylar Resources L.P. assigned the power purchase agreement to Townsite Solar, LLC.

Whitegrass Geothermal Renewable Purchase. In 2020, SCPPA, on behalf of Glendale, signed a long-term power purchase agreement with Whitegrass No. 1, LLC for the annual delivery of 3 MW or approximately 23,000 MWh annually of renewable geothermal energy from the Whitegrass Geothermal Project located in Lyon County, Nevada. Glendale has a 100% entitlement interest in the total energy, capacity, and environmental attribute rights produced by the project. The deliveries began on April 1, 2020 and the contract ends on December 31, 2045. In the Fiscal Year ended June 30, 2025, Whitegrass Geothermal Project provided 21,622 MWh of energy to Glendale.

Star Peak Geothermal Renewable Purchase. In 2020, SCPPA, on behalf of Glendale, signed a long-term power purchase agreement with Star Peak Geothermal, LLC for the annual delivery of 12.5 MW or approximately 100,000 MWh annually of renewable geothermal energy from the Star Peak Geothermal Energy Project which will be developed in Pershing County, Nevada. Glendale has a 100% entitlement interest in the total energy, capacity, and environmental attribute rights produced by the project. The project started delivering power in September 2022, and the contract ends on December 31, 2045. In the Fiscal Year ended June 30, 2025, Star Peak Geothermal Project provided 50,593 MWh of energy to Glendale.

Eland I Solar and Storage Purchase. In December 2019, SCPPA, on behalf of Glendale and the Los Angeles Department of Water and Power, signed a 25-year power purchase agreement with 68SF 8ME, LLC for the purchase of renewable solar energy, battery energy storage system capacity, and environmental attribute rights from the Eland I Solar and Storage Center. The facility will be developed in Kern County, California. The energy will be delivered at Barren Ridge, and Glendale has entered into an agreement with the Los Angeles Department of Water and Power for the transmission of the energy to Glendale. Glendale has a 12.5% entitlement interest in the total capacity, energy, storage and environmental attribute rights produced by the facility, or 25 MW of renewable solar energy and 18.75 MW/75 MWh of battery storage capacity. The project began commercial operation on November 18, 2024. In the Fiscal Year ended June 30, 2025, Eland I Solar and Storage Project provided 68,791 MWh of energy to Glendale. Glendale is not a participant in phase II of the Eland project.

Fuel Supply

In the Fiscal Year ended June 30, 2025, Glendale generated approximately 4% of its electric energy requirements from local generating units which burn natural gas and are available for emergency operations and to provide operating reserves.

Glendale has firm contracts with respect to out of state transmission pipelines and gas supplies for 3,989 million British thermal units ("MMBtu") of natural gas per day. In addition, natural gas is purchased from the spot market at the Southern California Gas City-Gate. The Southern California Gas Company ("SCG") provides intrastate delivery of natural gas to Glendale's Grayson Power Plant and to the Magnolia Power Plant in Burbank.

Interstate Transportation. Natural gas is the primary fuel supply for Glendale's local generating requirements. Canadian natural gas is transported using Glendale's firm transportation on the TransCanada pipeline system and the PGT pipeline to the Pacific Gas & Electric Company ("PG&E") system at Malin (near the California-Oregon border), then into the SCG system at Wheeler Ridge (near Bakersfield, California) using Glendale's PG&E entitlement.

SCG provides transportation of gas to local generating plants from Topock on the east and from the PG&E expansion line terminus at Wheeler Ridge to the north. The current volumetric tariff rate is $2.5118 per MMBtu. There are a number of factors, including those described in the "Green Book" of the California Public Utilities Commission (the "CPUC") on natural gas industry restructuring, which could affect the tariff rate or fundamentally change Glendale's costs for intrastate gas transmission. In addition, intrastate transport costs are expected to increase due to pipeline safety investments by PG&E and SCG.

Biogas Renewable Generation Project. In November 2021, the City Council certified the EIR for the Biogas Renewable Generation Project. The project entails installation of generation units at the Scholl Canyon landfill site so that the landfill gas can be directly processed to generate energy at the Scholl Canyon site. The Scholl Canyon site is located in the City. The Biogas Renewable Generation Project has an estimated cost of $76 million and the project would be completed over a course of approximately 48 months. On January 24, 2023, the City Council approved a full notice to proceed for the second and final phase of the project. The project will have four Jenbacher gas engine generators that will generate approximately 11 megawatts of power. Per modeling done by the consultant on the future gas production and degradation of landfill gas after its closure, there will be sufficient gas production to run the proposed four engines until 2034, and three engines until 2042. During this time, the Biogas Renewable Generation Project will generate approximately 10.5 to 12 megawatts (four engines) and 7.7 to 9 megawatts (three engines) of gross renewable power. After 2042, there will be only two engines running and generating an estimated 6 megawatts of gross power. The anticipated commercial operation date is in June 2026.

Natural Gas Reserves Project. In June 2005, Glendale elected to participate in the Pinedale Natural Gas Project through SCPPA for up to 2,000 MMBtu per day. The project provides for the acquisition and development of gas resources, reserves, fields, wells, and related facilities to provide a long-term supply of natural gas for its participants. Glendale's share in the project is 4.2553%. The first acquisition by the project was completed on July 1, 2005 with the total cost to the participants (including LADWP which acquired its share directly and not through SCPPA) of $306.1 million, of which Glendale cash funded approximately $13 million for its share. The acquisition, located in Pinedale, Wyoming, is expected to provide Glendale with peak daily volume of between 700 to 900 MMBtu. In the Fiscal Year ended June 30, 2025, Glendale received peak daily volume of approximately 345 MMBtu. Glendale Water and Power has reserved $16 million to fund the drilling programs of the Pinedale property and for future acquisitions.

Prepaid Natural Gas Project. In October 2007, Glendale 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 their other respective gas-fired generation stations. In connection with the prepaid natural gas financing, Glendale entered into a natural gas supply agreement with SCPPA pursuant to which Glendale purchases natural gas at a discount from the spot price over a term of 30 years (25 years as of a restructuring completed in 2009) which is scheduled to terminate at the end of October 2032. In the Fiscal Year ended June 30, 2025, this natural gas supply agreement provided approximately 29% of Glendale's gas requirements for the Grayson Power Plant and the Magnolia Power Project.

Existing Transmission Resources

Transmission resources are an integral component of Glendale's plan to provide economical and reliable electric service to its customers. Glendale currently has several firm capacity transmission agreements (ownership and long-term leases) to deliver up to 262 MW of remote generation to the Air Way Receiving Station in Glendale and to provide access to major hubs of the western wholesale power market. The transmission network currently allows Glendale to obtain energy supplies and enables sales and exchanges of energy during low load periods. Glendale has sufficient transmission resources during low-load periods, but during high-load periods must leverage local generation because of constrained transmission resources. Depending on the generation source, the energy is transmitted through a combination of the following transmission resources.

GLENDALE WATER AND POWER
FIRM TRANSMISSION SERVICE AGREEMENTS
(as of June 30, 2025)

Transmission Line/Path	Owner/Party	Glendale's Capacity	Primary Use
Pacific Northwest DC Intertie	Glendale	115 MW	NW Market
Northern Trans. System (NTS)	IPA/Utah	33/3 MW[(1)]	SW Markets
Southern Trans. System (STS)	SCPPA	55 MW	IPP
Victorville/Adelanto-Air Way	LADWP	112 MW	IPP, Hoover, PVNGS, SW Markets
Mead-Phoenix	SCPPA	41 MW	PVNGS, Westwing, Marketplace
Mead-Adelanto	SCPPA	112 MW	PVNGS, Marketplace
Sylmar-Air Way	LADWP	150 MW	NW and SW Markets
Burbank-Glendale Interconnection	Glendale/ Burbank	125 MW	Magnolia

(1) Glendale has rights to approximately 33 MW between IPP and Mona Substation and 3 MW between IPP and Gonder Substation. These rights vary by season and direction.

Source: Glendale Water and Power.

Pacific Northwest DC Intertie. Spanning 850 miles from Celilo in northern Oregon to Sylmar, California, the Pacific Northwest DC Intertie is a double-pole, +1-500 kV transmission line operated as a single path with separate ownership north and south of the Nevada-Oregon border ("NOB"). The Pacific Northwest DC Intertie conveys energy to Glendale from Pacific Northwest utilities and Glendale's interests in renewable energy projects in the northwest. Glendale is entitled to 115 MW (3.846%) of the total 3,100 MW capacity of the southern portion (south of the point where the line crosses the NOB of the Pacific Northwest DC Intertie). Because of the load diversity and excess hydroelectric energy in the spring during most years, the Pacific Northwest DC Intertie provides Glendale with opportunities for economical energy imports.

Northern Transmission System. The NTS consists of two 50-mile long 345-kV AC transmission lines which connect the IPP to the Mona Substation in Utah and the Gonder Substation in Nevada. Glendale has entitlements of 24 MW and 3 MW of capacity, respectively, on these transmission lines as a result of the IPP Excess Sales Contract with the Utah participants. These rights vary by season and according to the terms of the agreement. Under the IPP Repowering Project, Glendale has 0 MW of capacity on the NTS line.

Southern Transmission System. The Southern Transmission System ("STS") is a double-pole, +/- 500-kV DC transmission line spanning 488 miles from the IPP in central Utah to the Adelanto Substation in Southern California, together with an AC/DC converter station at each end. It is operated and maintained by LADWP under contract with IPA. In connection with its entitlement to the IPP, Glendale acquired a contractual entitlement to 44 MW (2.3%) of the total 1,920 MW capacity of the STS (prior to the upgrade, as described in the following paragraph) through a transmission system contract with SCPPA. Under the IPP Repowering Project, Glendale has 127 MW of capacity on the STS line.

To have access to potential renewable energy resource development available in central Utah and the Rocky Mountain region, and to have access to the potential energy in that area, the California participants in IPP initiated the STS Upgrade Project, which increased the transfer capability of the STS by 480 MW. The STS Upgrade Project increased the capacity of the Southern Transmission System from 1,920 MW to 2,400 MW, increasing Glendale's entitlement in the STS increased by 11 MW to 55 MW. Glendale has entered into a transmission service contract with SCPPA which obligates Glendale to pay the cost of its share of the transfer capability on a "take-or-pay" basis.

Southern Transmission System Renewal Project. In connection with the IPP Repowering Project, SCPPA is financing the costs of acquisition and construction of additional capital improvements to the Southern Transmission System (the "STS Renewal Project"), which initially will include new converter stations and AC switchyard expansions at the Adelanto Converter Station and the Intermountain Converter Station, and reactive power equipment. Glendale has entered into a renewal transmission service contract related to the STS Renewal Project. Under such an existing agreement with IPP and such renewal transmission service contract Glendale is obligated to pay the cost of its share of the transfer capability on a "take-or-pay" basis.

The Renewal Power Sales Contracts provided a process for IPP members to subscribe for shares of the new gas-fired or alternative repowering plant. On July 23, 2019, the City Council approved GWP's recommendation for continued participation in the IPP project which enabled Glendale to retain its 4.166% share of the project. Upon the expiration of certain original agreements in 2027, Glendale's share of the STS Renewal Project will be 5.278%.

Victorville/Adelanto-Air Way Transmission System. Glendale has contracts with LADWP for 112 MW of transmission capacity (net of losses) from either Adelanto or Victorville to the Air Way Receiving Station.

Mead-Phoenix Transmission Project, SCPPA Interest (Multiple Members). Glendale is a participant in SCPPA's member-related interest in the Mead-Phoenix Transmission Project, a 256 mile, 500-kV AC transmission line that extends between a southern terminus at the existing Westwing Substation (in the vicinity of Phoenix, Arizona) and a northern terminus at Marketplace Substation, a substation located approximately 17 miles southwest of Boulder City, Nevada. Glendale has entered into a transmission service contract with SCPPA under which SCPPA has sold to Glendale, on a "take-or-pay" basis, its entitlement share of 16.5% (approximately 41 MW) of SCPPA's member-related ownership interest in the Mead-Phoenix Transmission Project and which obligates Glendale to pay its share of debt service on bonds issued by SCPPA for the project, as well as capital costs and costs related to operation and maintenance.

Mead-Adelanto Transmission Project, SCPPA Interest (Multiple Members). Glendale is entitled to 112 MW (7.5%) of transmission capacity from the Mead-Adelanto Transmission Project, an approximately 202-mile, 500-kV AC transmission line that extends between a southwest terminus at the existing Adelanto Substation in southern California and a northeast terminus at Marketplace Substation, a substation located approximately 17 miles southwest of Boulder City, Nevada. Glendale has entered into a transmission service contract with SCPPA, under which SCPPA has sold to Glendale, on a "take-or-pay"

basis, its entitlement share of SCPPA's member-related ownership interest in the Mead-Adelanto Transmission Project. Glendale's transmission service contract with SCPPA obligates Glendale to pay its share of debt service on bonds issued by SCPPA for the project, as well as capital costs and costs related to operation and maintenance.

Sylmar-Air Way. Glendale has two contracts with LADWP for 100 MW and 50 MW of firm transmission service from the Sylmar Receiving Station to the Air Way Receiving Station. These contracts are for the delivery of energy transmitted over the Pacific Northwest DC Intertie and for delivery of energy purchased from Southwest markets.

Sylmar Services Agreement. Glendale has a contract with LADWP for 115 MW of transfer rights through the Sylmar Switching Station into and out of the California Independent System Operator, which allow for the transfer of energy to/from the Pacific Northwest and to/from Glendale.

Glendale participates in energy markets of the California Independent System Operator (the "ISO") but currently does not intend to transfer control of its transmission resources to the ISO. Glendale has no firm plans to increase its transmission capacity.

Wholesale Transactions

In addition to making market purchases, Glendale sells wholesale energy, which includes electrical energy and capacity, ancillary services, transmission, renewable energy attributes, emission allowances, carbon allowances and carbon emission offsets, natural gas, transportation, imbalance and storage. When necessary, energy traders seek opportunities to market short-term energy transactions. All transactions are conducted within the Energy Risk Management Policy last approved by the City Council in May 2025.

Glendale's volume of short-term transactions on the electric wholesale market has fluctuated with market conditions in the western United States as have the revenues Glendale Water and Power has been able to realize by selling energy to third parties. Gross sales to third parties were $22,875,000 in Fiscal Year 2020-21, $29,862,000 in Fiscal Year 2021-22, $40,113,000 in Fiscal Year 2022-23, $20,666,000 in Fiscal Year 2023-24, and $15,044,000 in Fiscal Year 2024-25.

Interconnections and Distribution Facilities

Glendale's power system is inside the LADWP balancing area and is interconnected to the LADWP system at Air Way Receiving Station and to the Burbank system at Western Substation. Glendale owns facilities for the distribution of electric power to retail customers. These facilities include approximately 60 miles of 34/69-kV power lines, approximately 498 miles of 4/12-kV distribution lines (of which approximately 50% are underground), two switching substations, 12 distribution substations and 104 distribution feeders. The 69-kV Kellogg Switching station, a gas insulated station ("GIS"), includes state-of-the-art relays and devices. In 2011, one distribution substation was reconstructed from an air-insulated substation to GIS and converted from a 34.5/4-kV station to a 69/12-kV station. The project included conversion of 4 kV distribution services to 12 kV in the service area. In 2016, a second distribution substation was reconstructed from an air-insulated substation to GIS and converted from a 34.5/4-kV station to a 69/12-kV station. The project included conversion of 4 kV distribution services to 12 kV in the service area. In 2017, a 2 MW battery energy storage system was installed and connected to Kellogg 69-kV Switching Substation.

Electric Rates and Charges

Glendale is obligated by its Charter and the indenture of trust under which its Electric System bonds are issued to establish rates and collect charges in an amount sufficient to meet its expenses of operation and maintenance and debt service requirements (with specific requirements as to priority and coverage). Electric rates for Glendale are recommended by the Commission and are subject to approval by the City Council. Electric rates are not subject to regulation by the CPUC or by any other agency of the State of California (the "State"). The State Constitution requires that electric rates be based upon the cost of service to the various customer classes.

In addition, State Legislative Assembly Bill 1890 requires the imposition of a public benefits charge ("PBC") of 2.85% of annual revenue requirements. Beginning in January of 1998, Glendale collected this PBC as a 2.85% charge applied to all electric charges. In September of 1999, the City Council approved changes to the electric rates to collect the PBC beginning on January 1, 2000 as a charge per kilowatt hour ($0.002963 per kilowatt hour). In February of 2008, the City Council approved changes to the electric rates to collect the PBC beginning in March of 2008 as a percentage of the electric bill. The current rate is 2.85% of all electric charges.

For customers of the Electric System, the electric rates are composed of (i) a meter charge component, designed to cover a portion of the fixed costs of the Electric System, and (ii) an energy charge calculated based on usage. Some rate schedules are also subject to a demand charge and a reactive power charge. The electric rates also include bi-annual adjustable rates (made up of an Energy Cost Adjustment Charge and a Regulatory Adjustment Charge) which adjust the customer's electric bill upwards or downwards to reflect variation from the projected cost of purchased power, fuel and regulatory expenses. In addition, a Revenue Decoupling Charge (or Revenue Decoupling Credit) is applied to the customer's electric bill twice a year to reflect the variance from actual sales when compared to projected sales. Increases to the energy cost adjustment charge are limited to no more than one-half cent ($0.005) per kilowatt-hour during any 12-month period, except under limited circumstances such as an extended outage of a major resource or large and sustained fuel price increases, in which case the Energy Cost Adjustment Charge may be increased by up to an additional one cent ($0.01) per kilowatt-hour during any 12-month period.

The following table sets forth the average rates for the indicated customer classes for the Fiscal Years ended June 30, 2021 through June 30, 2025, including the Energy Cost Adjustment Charge, Regulatory Adjustment Charge, and Revenue Decoupling Charge (or Revenue Decoupling Credit, as applicable).

GLENDALE WATER AND POWER
FIVE-YEAR HISTORY OF ELECTRIC SYSTEM RATES
Average Rate – Dollars Per Kilowatt Hour

	Fiscal Year Ended June 30,				
Customer Class	**2025**	**2024**	**2023**	**2022**	**2021**
Residential	$0.3633	$0.2814	$0.2398	$0.2238	$0.2117
Commercial	0.2860	0.2538	0.2196	0.2056	0.2031
Industrial	0.2341	0.2043	0.1971	0.1801	0.1819
Lighting	0.0002	0.0002	0.0008	0.0008	0.0007

Source: Glendale Water and Power.

Between Fiscal Years 2018-19 through 2022-23, the Electric System's base rate has been increased four times. Due to the COVID-19 Pandemic, a 1% increase scheduled to become effective on July 1, 2020, was deferred one year by the City Council to July 1, 2021, and the subsequent two annual rate increases were also deferred by one year. The increased revenues from the rate increases in the base rates are intended to cover the rising costs of labor and materials and to further replenish the cash reserves.

In 2023, Glendale completed a rate study. The rate study was required to determine what if any rate increases might be needed to support the recently approved and proposed clean energy programs. The rate study also took into account the revised cost estimates for the Grayson Repower Project and the Biogas Renewable Project, as well as impacts COVID-19 may have on current and future electric sales and revenues. The rate study recommended overall system rate increases of 14.8%, 11.3% and 11.3% over three years, respectively. The City Council approved the series of rate increases in November 2023 that were to take effect January 1, 2024, July 1, 2024 and July 1, 2025, respectively. On June 3, 2025 the City Council approved a rate plan to defer the July 1, 2025 rate increases (scheduled to be 11.3% overall) to November 1, 2025 and reduce the increases to an overall system average of 5%. Additional increases to overall system rates were also approved at 2.95% effective on November 1, 2026 and 2.95% on November 1, 2027.

The City Council has an approved cash reserve policy for the Electric System. The currently approved level is $124.1 million. The cash reserve consists of moneys on deposit in an operating reserve, a contingency reserve, a rate stabilization reserve and a gas reserve. As of June 30, 2025, $124.1 million was designated.

The following table sets forth historical percentage increases in rates for the indicated customer classes per the Electric Rate Plan and in the rates approved in 2018 and in 2023. Such percentage changes do not reflect changes in the Fuel Adjustment Charge (prior to 2013) or in the Energy Cost Adjustment Charge, Regulatory Adjustment Charge, and Revenue Decoupling Charge (or Revenue Decoupling Credit, as applicable) (after 2013).

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GLENDALE WATER AND POWER
PERCENTAGE INCREASE IN ELECTRIC RATES

Effective	Overall System	Residential	Commercial	Industrial	Lighting
7/01/2007	8.1%	8.8%	7.1%	8.5%	0.0%
9/13/2013	8.0	8.8	7.2	7.9	0.0
7/01/2014	7.0	7.7	6.3	6.9	0.0
7/01/2015	5.0	5.5	4.5	4.9	0.0
7/01/2016	2.0	2.2	1.8	2.0	0.0
7/01/2017	2.0	2.2	1.8	2.0	0.0
7/01/2018	0.0	0.0	0.0	0.0	0.0
7/01/2019	0.5	3.2	(1.0)	(1.2)	0.0
7/01/2020[(1)]	0.0	0.0	0.0	0.0	0.0
7/01/2021	1.0	3.2	(0.3)	(0.5)	0.0
7/01/2022	1.0	3.1	(0.4)	(0.3)	0.0
7/01/2023	1.0	3.0	(0.3)	(0.4)	0.0
1/01/2024	14.8	18.6	9.7	12.1	0.0
7/01/2024	11.3	14.0	7.5	9.4	0.0
11/01/2025	5.0	6.1	3.3	4.2	0.0
11/01/2026	2.95	3.6	2.0	2.5	0.0
11/01/2027	2.95	3.6	2.0	2.5	0.0

[(1)] In June 2020, the City Council deferred the scheduled July 1, 2020 increase by one year to July 1, 2021, and deferred the subsequent two annual rate increases by one year.

[(2)] On June 3, 2025 the City Council approved a rate plan to defer the July 1, 2025 rate increases (scheduled to be 11.3% overall) to November 1, 2025 and reduce the increases to an overall system average of 5%. Additional increases to overall system rates were also approved at 2.95% effective on November 1, 2026 and 2.95% on November 1, 2027.

Source: Glendale Water and Power.

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Customers, Energy Sales, Revenues and Demand

The average number of customers, MWh sales and revenues derived from sales, by classification of service, during the past five Fiscal Years, are listed below.

GLENDALE WATER AND POWER
ELECTRIC SYSTEM
CUSTOMERS, SALES, REVENUES AND DEMAND

	Fiscal Year Ended June 30,				
	2025	**2024**	**2023**	**2022**	**2021**
Number of Customers:					
Residential	78,071	77,563	77,188	76,929	76,757
Commercial	13,275	13,221	13,184	13,140	13,108
Industrial	183	183	185	193	193
Other (Government)	21	21	21	21	21
Total	91,550	90,988	90,578	90,283	90,079
Megawatt-Hour Sales:					
Residential	384,218	375,266	402,751	381,594	400,862
Commercial	311,450	304,966	307,505	310,816	294,782
Industrial	288,131	284,737	280,350	283,930	273,434
Public Street & Highway Lighting	9,210	9,226	9,245	9,185	9,173
Total Retail Energy Sales	993,009	974,195	999,852	985,525	978,251
Sales to Other Utilities[(1)]	104,008	224,585	397,991	419,063	482,809
Total Energy Sales	1,097,017	1,198,780	1,397,843	1,404,588	1,461,060
Revenues from Sale of Energy:					
Residential	$139,602,000	$105,618,000	$96,598,000	$85,439,000	$ 84,866,000
Commercial	86,172,000	74,409,000	64,563,000	61,001,000	56,915,000
Industrial	67,463,000	58,172,000	55,248,000	52,586,000	49,740,000
Public Street & Highway Lighting	2,908,000	3,002,000	2,961,000	2,933,000	2,961,000
Sales to Other Utilities[(1)]	15,044,000	20,666,000	40,113,000	29,862,000	22,875,000
Total Energy Sales	$311,189,000	$261,867,000	$259,483,000	$231,821,000	$217,357,000

(1) Fluctuations in sales to other utilities revenues were due primarily to changing market demand.
Source: Glendale Water and Power.

For the Fiscal Year ended June 30, 2025, approximately 47% of Glendale's electric sales revenues were derived from sales to residential customers, while industrial and commercial customers represented approximately 23% and 29% of sales revenues, respectively. Additional revenues, other than retail sales, were generated from sales to governmental agencies, and sales to other utilities.

Within Glendale, large commercial and industrial customers are principally institutions and large corporations (such as hospitals, entertainment companies, and high-rise office buildings). No single large commercial/industrial customer accounted for more than 3% of total electric sales revenues during the Fiscal Year ended June 30, 2025. The top 10 industrial customers represented approximately 14% of total electric sales revenues during the Fiscal Year ended June 30, 2025.

Capital Requirements

Glendale currently expects capital requirements for the Electric System for the current and next four Fiscal Years to aggregate approximately $364 million. This includes capital requirements such as the Grayson Repowering Project and the Biogas Renewable Generation Project at the Scholl Canyon site. See "Electric Rates and Charges" above. It is expected that these requirements will be funded from a combination of revenues, bond proceeds and cash reserves of the Electric System. The Grayson Repowering Project is projected to require since inception $640 million in capital expenditures through Fiscal Year 2026-27. The Biogas Renewable Generation Project is expected to require $76 million in capital expenditures over a two-year period starting in Fiscal Year 2023-24.

The following table lists the expected yearly capital requirements of the Electric System for the five Fiscal Years indicated.

GLENDALE WATER AND POWER
ELECTRIC SYSTEM
CAPITAL REQUIREMENTS
($ in Thousands)

Fiscal Year	Capital Requirements*
2026	$274,111
2027	33,447
2028	26,025
2029	15,225
2030	15,225
Total	$364,033

* Includes Grayson Repowering Project and Biogas Renewable Generation Project.
Source: Glendale Water and Power.

Insurance

Glendale carries property insurance through Arthur J. Gallagher Insurance Company for Glendale Water and Power. The property insurance policy covers "All Risk of Direct Physical Loss or Damage including Flood, excluding Earthquake." Current deductibles range from $25,000 to $250,000. Sub-limits apply to various specific components of this coverage.

Glendale is self-insured and administered for workers' compensation claims. Funding for this protection is provided through an Internal Service Fund. Glendale carries an excess workers' compensation insurance policy with a $2 million self-insured retention. Glendale is also self-insured for unemployment insurance, general auto and public liability through separate Internal Service Funds. Glendale carries an excess liability insurance policy with a $2 million self-insured retention and a $27 million limit. A claims payable liability has been established in these funds based on a case-by-case basis with estimates of reported claims and an estimate for claims incurred but not reported. Management of Glendale believes that provisions for claims at June 30, 2025 are adequate to cover the net cost of claims incurred to that date. However, such liabilities are, by necessity, based upon estimates and there can be no assurance that the ultimate cost will not exceed such estimates.

Transfers to the General Fund

The City Charter provides that the credit balance, if any, or any part thereof, in the Electric Works Revenue Fund at the end of any Fiscal Year (that is, the amount of which is in excess of the amount of all outstanding demands and liabilities unpaid from said fund on account of budget appropriations therefrom), shall be transferred to the Glendale Water and Power Surplus Fund. The Charter also provides that at the end of each Fiscal Year, up to 25% of the operating revenues of Glendale Water and Power for such Fiscal Year, excluding receipts from power supplied to other cities or utilities at wholesale rates, shall be transferred from the Glendale Water and Power Surplus Fund and further transferred to the City's General Reserve Fund; provided, however, that the City Council, on an annual basis, may reduce or eliminate the amount to be transferred if the City Council determines that such reduction or elimination is necessary to assure the sound financial position of Glendale Water and Power.

Since the Fiscal Year ended June 30, 2021, the Electric System has transferred between $17.5 million and $29.6 million per year from the Electric Works Revenue Fund to the City's general fund. Glendale's Fiscal Year 2025-26 budget includes a transfer of $ 32.6 million from the Electric Works Revenue Fund to the City's general fund.

Indebtedness; Joint Powers Agency Obligations

Electric System Revenue Bonds. As of December 1, 2025, in addition to joint powers agency obligations, Glendale had $595 million in outstanding principal amount of long-term obligations payable from net revenues of the Electric System (after the payment of operating and maintenance expenses of the Electric System, including Glendale's obligations with respect to its agreements with joint powers agencies as described under "– *Joint Powers Agency Obligations*" below) consisting of (i) $47,050,000 in outstanding principal of Electric Revenue Bonds, 2016 Refunding Series; (ii) $164,560,000 in outstanding principal of Electric Revenue Bonds, 2024 Series, (iii) $49,760,000 in outstanding principal of Electric Revenue Bonds, 2024 Refunding Series, (iv) $165,480,000 in outstanding principal of Electric Revenue Bonds, 2024 Second Series and (v) $168,235,000 in outstanding principal of Electric Revenue Bonds, 2025 Series.

Joint Powers Agency Obligations. As previously discussed, the City is a participant in the following SCPPA projects: the Palo Verde Nuclear Generating Station Project (of which no bonds are outstanding), the Southern Transmission System Project, the STS Renewal Project, the Mead-Phoenix Transmission Project, the Mead-Adelanto Transmission Project, the San Juan Unit 3 Project (which was shut down on December 31, 2017, and of which no bonds are outstanding), the Magnolia Power Project, the Prepaid Natural Gas Project, the Natural Gas Project (but the City has no obligation to pay debt service on the Natural Gas Project bonds), the Tieton Hydropower Project, the Linden Wind Energy Project, the Windy Point Project and the Milford Wind Corridor Phase II. See "– Joint Powers Agency Resources/Remote Ownership Interests." To the extent the City participates in projects developed by SCPPA, the City is obligated to pay for its proportionate share of the cost of the particular project (see, however, "– *Contingent Obligations Wind Energy Projects*" below for a discussion of certain costs now covered by LADWP). In addition, the City has entered into certain power sales contracts with IPA and others for the delivery of electric power from the Intermountain Power Project.

Agreements of the City with SCPPA (other than the agreement relating to SCPPA's Prepaid Natural Gas Project bonds) and IPA are on a "take-or-pay" basis, which requires payments to be made whether or not projects are completed or operable, or whether output from such projects is suspended, interrupted or terminated. Such payments represent the City's share of current and long-term obligations.

Payment for these obligations is expected to be made from operating revenues received during the year that payment is due. All of these agreements (other than the agreements relating to SCPPA's Prepaid Natural Gas Project bonds) contain "step-up" provisions obligating the City to pay a share of the obligations of any defaulting participant. The City's participation and share of the principal obligations of SCPPA and IPA (without giving effect to any "step-up" provisions) are shown in the following table.

GLENDALE WATER AND POWER
OUTSTANDING IPA AND SCPPA OBLIGATIONS
(as of December 1, 2025)

	Outstanding Debt	City's Participation[(1)]	City's Share of Principal Amount of Outstanding Debt[(2)]
IPA			
Intermountain Power Project	$ 112,520,000	2.044%	$2,299,507
Renewal Project	1,695,130,000	4.167	70,636,067
SCPPA			
STS Project	72,190,000	2.274	1,641,601
STS Renewal Project	1,790,705,000	5.278	94,513,410
Magnolia Power Project[(3)]	187,770,000	17.254	32,397,836
Prepaid Natural Gas Project	219,555,000	23.000	50,497,650
Tieton Hydropower Project.....	26,585,000	50.000	13,292,500
Linden Wind Energy Project.....	74,765,000	10.000	7,476,500[(4)]
Windy Point Project/Windy Flats …..……	126,675,000	7.630	9,665,303[(5)]
Milford Wind Corridor Phase II.....	52,135,000	4.902	2,555,658[(6)]
TOTAL	$4,358,030,000		$284,976,032

(1) Participation obligation is subject to increase upon default of another project participant (other than with respect to SCPPA's Prepaid Natural Gas Project bonds).
(2) Does not include interest on the debt.
(3) Excludes bonds relating solely to City of Cerritos.
(4) LADWP has purchased from Glendale its 10.0% output entitlement share and has agreed to pay costs associated therewith.
(5) LADWP has purchased from Glendale its 7.630% output entitlement share and has agreed to pay costs associated therewith.
(6) LADWP has purchased from Glendale its 4.902% output entitlement share and has agreed to pay costs associated therewith.
Source: Glendale Water and Power; IPA.

For the Fiscal Year ended June 30, 2025, Glendale's payments of debt service on its joint powers agency obligations aggregated approximately $5.7 million. Annual debt service on Glendale's joint powers agency obligations is expected to increase to approximately $25 million due to the Intermountain Power Renewal Project. This projection assumes no additional future debt issuances. 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.

Contingent Obligations for Wind Energy Projects. Glendale has entered into three power sales agreements with SCPPA, under which SCPPA has sold to Glendale on a "take-or-pay" basis, its entitlement

share of the capacity and energy in three separate projects; those being (i) an entitlement share of 10.0% of the Linden Wind Energy Project, which consists of the acquisition by SCPPA of an approximately 50 MW nameplate capacity wind powered electric generating facility comprised of 25 wind turbines located near the town of Goldendale in Klickitat County, Washington, including the structures, facilities, equipment, fixtures, improvements and associated real and personal property and other rights and interests necessary for the ownership and operation of the generation facility and the sale of energy therefrom, (ii) an entitlement share of 4.902% of the Milford Wind Corridor Phase II Project, which consists of the purchase by SCPPA of all energy generated by a 102 MW nameplate capacity wind powered electric generating facility comprised of 68 wind turbines located near Milford, Utah, for a term of 20 years (unless earlier terminated), and (iii) an entitlement share of 7.630% of the Windy Point/Windy Flats Project, which consists primarily of the purchase by SCPPA of all energy generated by a 262.2 MW nameplate capacity wind powered electric generating facility comprised of 114 wind turbines and related facilities located in the Columbia Hills area of Klickitat County, Washington near the City of Goldendale, for a term of 20 years (unless earlier terminated). Under each power sales agreement Glendale is obligated to pay its share of debt service on bonds or notes issued by SCPPA for each such project, as well as certain capital and other costs related to operation and maintenance.

In connection with each of the aforementioned projects, Glendale, SCPPA and LADWP entered into power sales agreements wherein LADWP purchased from Glendale, and Glendale sold and assigned to LADWP, Glendale's output entitlement share of each such project for the term of Glendale's respective power sales agreement with SCPPA. Pursuant to each such contract, LADWP agreed to pay to SCPPA each month during the term of the respective contract, an amount equivalent to Glendale's share of the monthly costs payable by Glendale under its respective power sales agreement with SCPPA for such output entitlement share for such month, and such amounts received by SCPPA from LADWP are applied to discharge Glendale's obligations to pay such share of monthly costs under each respective power sales agreement. In addition, Glendale's other obligations under each power sales agreement with SCPPA are discharged to the extent, but only to the extent, that such obligations are performed by LADWP. Except as discharged as provided in the respective agreements, the obligations of Glendale to pay monthly costs and to perform its other obligations under each power sales agreement with SCPPA are not otherwise affected and the power sales agreement continues as an obligation of Glendale.

Historical Operating Results and Debt Service Coverage

The following table shows the historical operating results and debt service coverage on Glendale's outstanding Electric System bonds during the five Fiscal Years ended June 30, 2021 through June 30, 2025. The information relating to the Fiscal Years ended June 30, 2021 through June 30, 2025 was prepared by Glendale on the basis of its audited financial statements and information derived from its audited financial statements.

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GLENDALE WATER AND POWER
ELECTRIC SYSTEM
HISTORICAL OPERATING RESULTS AND DEBT SERVICE COVERAGE
($ in thousands)

	Fiscal Year Ended June 30,				
	2025	**2024**	**2023**	**2022**	**2021**
Operating Revenues					
Revenues	$327,688	$261,867	$259,483	$231,821	$217,357
Other Revenues Available for Debt Service[(1)]	31,176	32,683	18,409	6,371	13,961
Total Revenues Available for Debt Service	$358,864	$294,550	$277,892	$238,192	$231,318
Operating Expenses[(2)]					
Production[(3)]	$171,683	$142,589[(4)]	$190,083	$145,451	$141,136
Transmission & Distribution	52,377	46,312	47,884	34,657	38,428
Customer Accounting & Sales	10,223	8,869	9,689	12,070	8,340
Total Expenses	$234,283	$197,770	$247,656	$192,178	$187,904
Net Income Available for Debt Service	$124,581	$96,780	$30,236	$46,014	$43,414
Debt Service[(5)]	$26,642	$12,173	$12,167	$12,168	$12,071
Debt Service Coverage[(6)]	4.68x	7.95x	2.49x	3.78x	3.60x

(1) Other revenues available for debt service include interest revenues plus other non-operating revenues less other non-operating expenses excluding interest expenses. Does not include contributions in aid.
(2) Operating expenses exclude depreciation, gas depletion, capital expenditures and transfers to Glendale's general fund (which transfers are payable after the payment of debt service).
(3) Includes generation, fuel, purchase power and labor expenses.
(4) Production costs for the Fiscal Year ended June 30, 2024 are lower than the two prior Fiscal Years due to (i) operation of a single unit of the Grayson Power Plant, as all units except for Unit 9 were taken offline as of June 30, 2023 in preparation for demolition; (ii) moderate weather during the summer months of 2023; and (iii) lower natural gas prices in the spot markets relative to prior Fiscal Years.
(5) Represents debt service on Glendale's outstanding Electric System revenue bonds.
(6) Increase in Debt Service Coverage for the Fiscal Year ended June 30, 2024 due to decrease in production costs, and increase in interest income and rates.

Source: Glendale Water and Power.

The following Statement of Net Position information for the five Fiscal Years ended June 30, 2021 through June 30, 2025 has been prepared by Glendale based upon audited financial statements.

GLENDALE WATER AND POWER
ELECTRIC SYSTEM
STATEMENT OF NET POSITION
($ in thousands)

	Fiscal Year Ended June 30,				
	2025	**2024**	**2023**	**2022**	**2021**
ASSETS					
Current assets:					
Pooled cash and investments	$254,951	$ 97,111	$85,662	$136,560	$149,657
Cash with fiscal agent	37,537	25,926	2,543	2,332	2,538
Investment with fiscal agent	2,398	2,398	2,398	2,398	2,398
Interest receivable	2,722	1,661	1,709	1,422	1,063
Investment Gas/Electric Commodity	7,023	9,023	8,018	-	-
Pooled Restricted cash and investments	-	64,947	-	-	-
Accounts receivable, net	39,478	35,317	28,314	33,063	31,889
Inventories	20,615	12,809	11,484	9,704	9,401
Prepaid items	10,195	31,953	28,652	8,565	8,381
Total current assets	374,919	281,145	168,780	194,044	205,327
Non-current assets:					
Capital assets:					
Land	6,306	6,306	6,306	6,306	6,306
Natural gas reserve	22,178	22,176	22,175	22,171	22,166
Buildings and improvements	63,770	63,758	63,970	73,722	73,716
Machinery and equipment	449,716	446,307	440,728	512,684	513,741
Intangible assets	1,088	975	422	327	327
Less: accumulated depreciation	(382,495)	(374,182)	(370,730)	(414,831)	(398,901)
Natural gas depletion	(16,362)	(15,811)	(15,162)	(14,481)	(13,770)
Amortization	(686)	(544)	(276)	(241)	(156)
Construction in progress	418,945	162,863	29,695	9,086	8,075
Lease assets	89	212	212	203	-
Total capital assets	562,549	312,060	177,340	194,946	211,504
Pooled designated and invested cash	154,412	151,354	151,435	124,100	124,100
Restricted cash	12,306	51,626	44,463	41,417	24,032
Leases receivable	911	941	993	1,016	-
Total non-current assets	730,178	515,981	374,231	361,479	359,636
Total assets	1,105,097	797,126	543,011	555,523	564,963
Deferred outflows of resources related to pensions	14,045	22,153	25,077	8,898	9,569
Loss on refunding	2,865	3,093	3,391	3,627	3,863
Deferred outflows of resources related to OPEB	281	350	408	467	496
Total assets and deferred outflows of resources	1,122,288	822,722	571,887	568,515	578,891
LIABILITIES AND NET POSITION					
Current liabilities:					
Accounts payable	$110,486	$ 45,097	$29,236	$19,250	$12,035
Interest payable	8,893	4,765	2,447	2,572	2,691
Bonds payable, due in one year	14,658	10,900	7,431	7,126	6,841
OPEB liability	54	69	-	-	-
Deposits	2,557	2,224	1,726	1,355	1,277
Total current liabilities	136,648	63,055	40,840	30,303	22,844
Noncurrent liabilities:					
Bonds payable	472,466	301,125	126,097	133,529	140,655
Leases and subscriptions payable	300	376	86	125	-
OPEB liability	1,051	1,096	1,781	2,156	2,632
Net pension liability	67,312	73,326	72,144	37,753	68,975
Total noncurrent liabilities	541,129	375,923	200,108	173,563	212,262
Total liabilities	677,777	438,978	240,948	203,866	232,474
Deferred inflows resources related to pensions and OPEB	6,190	8,048	4,986	23,090	334
Total liabilities & deferred inflows of resources	683,967	447,026	245,934	226,956	235,440
Net position[(1)]:					

Net investment in capital assets	19,102	59,209	43,249	61,184	72,099
Restricted For					
Carbon Emissions	10,255	50,949	37,160	26,718	17,443
Restricted investment	-	-	-	7,281	919
Low carbon fuel standard	2,051	677	1,634	1,749	-
SCAQMD emission controls	-	-	5,669	5,669	5,669
Unrestricted	406,913	264,861	238,241	238,958	247,321
Total net position	$438,321	$ 375,696	$325,953	$341,559	$343,451

(1) In 2021, a prior period adjustment of $2,398,000 was made to decrease the beginning net position of the Electric Utility. In prior years, the OPEB liability was only recorded in the governmental activities, because of the immateriality of the allocated liability to the enterprise funds. In Fiscal Year 2020-21, due to the decrease in the discount rate, the OPEB liability increased and it became a material liability in the Electric Utility.

Source: Glendale Water and Power.

Employees of Glendale Water and Power

For the Fiscal Year ended June 30, 2025, Glendale Water and Power budgeted for approximately 328 full-time employees. Most Electric System employees are represented by the Glendale City Employees Association ("GCEA"), the International Brotherhood of Electrical Workers ("IBEW") and the Glendale Management Association ("GMA") in all matters pertaining to wages, benefits and working conditions. The GCEA and the GMA each entered into a memorandum of understanding with the City that will expire on June 30, 2027. Glendale has recognized Local 18 of IBEW as the exclusive representative of approximately 117 of the 245 full-time Electric System employees. The contract with IBEW, which was approved in January 2024, expires on July 31, 2027.

Wildfire Mitigation Measures

Approximately 62% the City encompasses geographical areas classified by CPUC fire threat maps as "Tier 2" or "Tier 3" fire-threat areas (i.e., areas of elevated or extreme risk from utility-associated wildfires). However, many of these areas do not contain any Electric System assets that could ignite a wildfire and many others are required to be managed by the property owners to be cleared for hazardous vegetation. The remaining areas that contain Electric System assets and that are not areas required to be managed by private owners constitute approximately 0.47% of the City's total area.

The City currently has undertaken a number of wildfire mitigation measures. These include:

- The City responds to red flag wind warnings issued for the area by the National Weather Service by de-energizing (without loss of customer load) the transmission line of the Electric System that runs across uninhabited hilly terrain with elevated fire risk. In addition, GWP is looking into employing the broken conductor technology and fast acting protection scheme to mitigate the risk of fire furthermore.

- The City has installed fire resistant wrap/coating poles in high fire risk locations and has installed covered conductors (in selected Tier 2 areas).

- The City expanded vegetation management to exceed minimum clearance requirements by trimming trees down to the telecommunications level.

- The City installed devices to minimize the risk of fire in brush areas from ejecting a blown fuse.

- To evaluate the effectiveness of its wildfire plan, the City developed metrics posted on an internal website to track the number of electrical assets replaced in Tier 2 and Tier 3 areas.

- The City expanded asset inspections and refined its master plan to address end-of-life infrastructure management and mitigate against fire risks from downed power lines or failed equipment that can spark and ignite wildfires. This inspection / assessment program includes pole inspections, vault inspections, and inspections of all assets connected to (or within) these assets, including (but not limited to) transformers, crossarms, insulators, conductors, cables, landings, capacitor banks, voltage regulators, and all other attachments. In addition to assessing the condition of Electric System assets, the program provides a mechanism to prioritize repair and replacement projects.

State fire-threat maps and fire-threat areas are revised from time to time. In March 2025, the California Department of Forestry and Fire Protection (hereinafter, "CalFire") released updated wildfire hazard severity zone maps for the Southern California region. These updated maps identify areas as "moderate," "high," and "very high" wildfire hazard severity zones in "local responsibility areas," where local fire departments are responsible for responding to fires, in order to reflect zones in California that are susceptible to wildfires. The updated maps increase the acreage in the City that is identified as a "very high" wildfire hazard severity zone and add identified areas of "moderate" and "high" wildfire hazard severity zones (which categories were not previously included in earlier versions of the CalFire fire hazard severity zone maps). These wildfire hazard severity zone maps differ from the CPUC Fire-Threat Maps referenced above. The CPUC Fire-Threat Map is designed specifically for identifying areas where there is an increased risk for utility associated wildfires. The updated CalFire wildfire hazard severity zone maps are being evaluated by the Department for their impact on future wildfire mitigation plans.

Litigation

General. At any given time, including the present, there are certain claims and disputes that arise in the normal course of the Electric System's enterprise activities. Such matters could, if determined adversely to Glendale or the Electric System, affect expenditures by Glendale, and in some cases, its Electric System revenues. The management of the GWP is of the view that no pending actions are likely to have a material adverse effect on Glendale's ability to pay its Electric System obligations.

Grayson Litigation

On March 18, 2022, the Sierra Club filed a Petition for Writ of Mandate against the City in the matter of *Sierra Club v. City of Glendale, et al.*, Los Angeles Court Case No. 22STCP00983. The Sierra Club petition challenged the City Council's February 15, 2022 certification of a Final Environmental Impact Report (an "FEIR") for the proposed Grayson Repowering Project and authorizations to move forward with various Grayson Repowering Project development activities. The case went to trial and on July 31, 2023, the trial court issued a statement of decision denying Sierra Club's petition. On October 30, 2023, Sierra Club filed a notice of appeal. The hearing on Sierra Club's appeal was held on September 3, 2024 in the California Court of Appeal. On November 27, 2024, the Court of Appeal issued a statement of decision affirming the trial court's judgment in favor of the City. The Sierra Club did not file a request for further review and therefore the litigation has concluded in favor of the City.

In a related case that the Los Angeles Superior Court coordinated with the Sierra Club matter, on March 21, 2022, the Glendale Residents Against Environmental Destruction ("GRAED") filed a Petition for Writ of Mandate against the City (*Glendale Residents Against Environmental Destruction v. City of Glendale, et al.*, Los Angeles Court Case No. 22STCP01021) also challenging the City Council's February 15, 2022 certification of an FEIR for the proposed Grayson Repowering Project and authorizations to move forward with various Grayson Repowering Project development activities. On July 31, 2023, the trial court issued a statement of decision denying GRAED's petition and entered a judgment denying the petition on August 28, 2023. GRAED filed a timely notice of appeal. The hearing

on GRAED's appeal was held on September 3, 2024 in the California Court of Appeal. On September 30, 2024, the Court of Appeal issued its decision denying GRAED's appeal and upholding the trial court's decision. GRAED did not file a request for further review and therefore the litigation has concluded in favor of the City.