PRELIMINARY OFFICIAL STATEMENT DATED __________ __, 2022

NEW ISSUE - BOOK-ENTRY ONLY **Ratings: See "RATINGS" herein.**

In the opinion of Nixon Peabody LLP, Special Tax Counsel to NCPA, under existing law and assuming compliance with the tax covenants described herein, and the accuracy of certain representations and certifications made by NCPA described herein, interest on the 2022 Series A Bonds is excluded from gross income for federal income tax purposes under Section 103 of the Internal Revenue Code of 1986, as amended (the "Code"). Special Tax Counsel is also of the opinion that such interest is not treated as a preference item in calculating the alternative minimum tax imposed under the Code. Interest on the 2022 Series B Bonds is not excluded from gross income for federal income tax purposes. Interest on all of the 2022 Bonds, including the 2022 Series B Bonds, is exempt from personal income taxes of the State of California (the "State") under present State law. See "TAX MATTERS" herein regarding certain other tax considerations.

NORTHERN CALIFORNIA POWER AGENCY
HYDROELECTRIC PROJECT NUMBER ONE REVENUE BONDS

$__________*	**$_________***
2022 Refunding Series A	**2022 Taxable Refunding Series B**

Dated: Date of Delivery **Due: July 1, as shown on the inside cover**

***This cover page contains certain information for general reference only. It is not intended to be a summary of the security or terms of the 2022 Bonds. Investors are advised to read the entire Official Statement to obtain information essential to the making of an informed investment decision. Capitalized terms used on this cover page not otherwise defined will have the meanings set forth herein*.**

Northern California Power Agency ("NCPA") is offering $_______* of its Hydroelectric Project Number One Revenue Bonds, 2022 Refunding Series A (the "2022 Series A Bonds") and $______* of its Hydroelectric Project Number One Revenue Bonds, 2022 Taxable Refunding Series B (the "2022 Series B Bonds" and together with the 2022 Series A Bonds, the "2022 Bonds"). The 2022 Bonds are being issued by NCPA pursuant to an Indenture of Trust, dated as of March 1, 1985, as amended and supplemented (the "Indenture"), by and between NCPA and U.S. Bank Trust Company, National Association, as successor trustee (the "Trustee"), for the purpose of providing funds to refund NCPA's Outstanding Hydroelectric Project Number One Revenue Bonds, 2008 Refunding Series A (the "Refunded 2008 Series A Bonds") and Hydroelectric Project Number One Revenue Bonds, 2012 Series A (the "Refunded 2012 Series A Bonds" and, together with the Refunded 2008 Series A Bonds, the "Refunded Bonds"), and to pay costs of issuance of the 2022 Bonds and other costs related to the refunding of the Refunded Bonds, including costs of termination of an interest rate swap agreement relating to the Refunded 2008 Series A Bonds. See "PLAN OF REFUNDING" herein.

The 2022 Bonds are being issued as fully registered bonds and, when issued, will be registered in the name of Cede & Co., as nominee of The Depository Trust Company, New York, New York ("DTC"). DTC will act as securities depository for the 2022 Bonds, and individual purchases of the 2022 Bonds will be made in book-entry form only. Interest on the 2022 Bonds of each Series is payable on each January 1 and July 1, beginning on [July 1, 2022]. Principal is payable on July 1 of the years and in the amounts set forth on the inside cover page hereof. The 2022 Bonds of each Series may be purchased in authorized denominations of $5,000 and any integral multiple thereof. Principal, premium, if any, and interest on the 2022 Bonds is payable by the Trustee to DTC, which is obligated in turn to remit such principal, premium, if any, and interest to its DTC Participants for subsequent disbursement to the beneficial owners of the 2022 Bonds. See "APPENDIX C–BOOK-ENTRY ONLY SYSTEM" hereto.

The 2022 Bonds are subject to redemption prior to maturity as described herein.

THE 2022 BONDS ARE SPECIAL, LIMITED OBLIGATIONS OF NCPA PAYABLE SOLELY FROM THE TRUST ESTATE, AND SECURED SOLELY BY A PLEDGE AND ASSIGNMENT OF THE TRUST ESTATE, CONSISTING PRIMARILY OF THE NCPA REVENUES (AS DEFINED HEREIN) AND THE OTHER FUNDS PLEDGED BY NCPA UNDER THE INDENTURE. THE 2022 BONDS DO NOT CONSTITUTE A CHARGE AGAINST THE GENERAL CREDIT OF NCPA. THE 2022 BONDS ARE NOT DEBTS, LIABILITIES OR OBLIGATIONS OF THE STATE OF CALIFORNIA, ANY PUBLIC AGENCY THEREOF (OTHER THAN NCPA), ANY MEMBER OF NCPA OR ANY PROJECT PARTICIPANT, AND NEITHER THE FAITH AND CREDIT NOR THE TAXING POWER OF ANY OF THE FOREGOING (INCLUDING NCPA) IS PLEDGED FOR THE PAYMENT OF THE 2022 BONDS. NCPA HAS NO TAXING POWER.

Maturity Schedules
(see inside cover)

The 2022 Bonds are offered when, as and if issued and delivered to the Underwriters, subject to the approval of legality by Stradling Yocca Carlson & Rauth, a Professional Corporation, Bond Counsel to NCPA, and certain other conditions. Certain legal matters will be passed upon for NCPA by Jane E. Luckhardt, Esq., General Counsel to NCPA, and by Spiegel & McDiarmid LLP, Washington, D.C., Washington, Counsel to NCPA. Nixon Peabody LLP is serving as Special Tax Counsel to NCPA in connection with the 2022 Bonds. Stradling Yocca Carlson & Rauth, a Professional Corporation, is serving as Disclosure Counsel to NCPA in connection with the 2022 Bonds. Certain legal matters will be passed upon for the Underwriters by Orrick, Herrington & Sutcliffe LLP, Counsel to the Underwriters. It is expected that the 2022 Bonds in definitive form will be available for delivery through the facilities of DTC in New York, New York, by Fast Automated Securities Transfer (FAST) on or about ______ __, 2022.

Citigroup **BofA Securities**

Dated: _________ _, 2022

* Preliminary, subject to change.

MATURITY SCHEDULES*

NORTHERN CALIFORNIA POWER AGENCY
HYDROELECTRIC PROJECT NUMBER ONE REVENUE BONDS

$___________*
2022 Refunding Series A Bonds

Maturity Date (July 1)	Principal Amount	Interest Rate	Yield	Price	CUSIP†
					664845___
					664845___
					664845___
					664845___
					664845___
					664845___

$_________*
2022 Taxable Refunding Series B

Maturity Date (July 1)	Principal Amount	Interest Rate	Yield	Price	CUSIP†
					664845____

* Preliminary, subject to change.

† CUSIP® is a registered trademark of the American Bankers Association. CUSIP data herein are provided by CUSIP Global Services, managed by S&P Global Market Intelligence on behalf of the American Bankers Association. CUSIP numbers have been assigned by an independent company not affiliated with NCPA or the Underwriter and are included solely for the convenience of the owners of the 2022 Bonds. Neither NCPA nor the Underwriter is responsible for the selection or use of these CUSIP numbers and no representation is made as to their correctness on the 2022 Bonds or as indicated above. The CUSIP number for a specific maturity is subject to being changed after the issuance of the 2022 Bonds as a result of various subsequent actions including, but not limited to, a refunding in whole or in part of such maturity or as a result of the procurement of secondary market portfolio insurance or other similar enhancement by investors that is applicable to all or a portion of the 2022 Bonds.

NORTHERN CALIFORNIA POWER AGENCY
651 Commerce Drive
Roseville, California 95678
Telephone: (916) 781-3636

NCPA Commissioners and Members

David Hagele, Chair .... Councilmember, City of Healdsburg	Gerald "Jerry" Serventi, Vice Chair .... Vice President, Public Utilities Board, City of Alameda
James "Bo" Sheppard .... Mayor, City of Biggs	Catalina Sanchez .... Councilmember, City of Gridley
Mark Chandler .... Mayor, City of Lodi	Jenelle Osborne .... Mayor, City of Lompoc
Gregory Scharff .... Representative, Utilities Advisory Commission, City of Palo Alto	Larry Price .... Board Member, Plumas-Sierra Rural Electric Cooperative
Jared Carpenter .... Manager of Utilities Administration, Port of Oakland	Julie Winter .... Councilmember, City of Redding
Pauline Roccucci .... Councilmember, City of Roseville	[Vacant] .... San Francisco Bay Area Rapid Transit
Sudhanshu "Suds" Jain .... Councilmember, City of Santa Clara	James Takehara .... Utility Director, City of Shasta Lake
Joe Horvath .... Asst. General Manager, Truckee Donner Public Utility District	Doug Crane .... Councilmember, City of Ukiah

Management

General Manager	Randy S. Howard
General Counsel	Jane E. Luckhardt, Esq.
Assistant General Manager, Finance and Administrative Services; Chief Financial Officer	Monty Hanks
Assistant General Manager, Legislative & Regulatory Affairs	Jane Dunn Cirrincione
Assistant General Manager, Power Management	Tony Zimmer
Assistant General Manager, Generation Services	Randy Bowersox

Project Participants

Participant	Project Entitlement Percentage
Alameda	10.00%
Biggs	0.10
Gridley	1.06
Healdsburg	1.66
Lodi	10.37
Lompoc	2.30
Palo Alto	22.92
Roseville	12.00
Santa Clara	35.86
Ukiah	2.04
Plumas-Sierra Rural Electric Cooperative	1.69
	100.00%

Special Services

Bond and Disclosure Counsel
Stradling Yocca Carlson & Rauth,
a Professional Corporation
Newport Beach, California

Special Tax Counsel
Nixon Peabody LLP
Washington, D.C.

Washington Counsel
Spiegel & McDiarmid LLP
Washington, D.C.

Auditor
Baker Tilly
US, LLP
Madison, Wisconsin

Trustee
U.S. Bank Trust Company,
National Association
New York, New York

Verification Agent
____
________, ________

Municipal Advisor
PFM Financial
Advisors LLC
Los Angeles, California

No dealer, broker, salesperson or any other person has been authorized by NCPA, the Project Participants or the Underwriters to give any information or to make any representation, other than the information and representations contained herein, in connection with the offering of the 2022 Bonds and, if given or made, such information or representations must not be relied upon as having been authorized by any of the foregoing. This Official Statement does not constitute an offer to sell or the solicitation of an offer to buy, nor will there be any sale of, the 2022 Bonds in any jurisdiction in which it is unlawful to make such offer, solicitation or sale. This Official Statement is not to be construed as a contract with the purchasers of the 2022 Bonds.

Statements contained in this Official Statement, which include estimates, forecasts or matters of opinion, are intended solely as such and are not to be construed as representations of fact. The information set forth herein has been furnished by NCPA, the Project Participants or other sources which are believed to be reliable. The information and expressions of opinion herein are subject to change without notice, and neither the delivery of this Official Statement nor any sale made hereunder shall, under any circumstances, create any implication that there has been no change in the matters described herein since the date hereof. This Official Statement, including any supplement or amendment hereto, is intended to be filed with the Municipal Securities Rulemaking Board through the Electronic Municipal Market Access (EMMA) website.

U.S. Bank Trust Company, National Association accepts its duties as Trustee for the 2022 Bonds. Notwithstanding the foregoing, however, the Trustee has not reviewed this Official Statement and makes no representations as to the information contained herein, including, but not limited to, any representations as to the financial feasibility of NCPA or its Members, the Project or any related activities.

The Underwriters have provided the following sentence for inclusion in this Official Statement: The Underwriters have reviewed the information in this Official Statement in accordance with, and as part of, their responsibilities to investors under the federal securities laws as applied to the facts and circumstances of this transaction, but the Underwriters do not guarantee the accuracy or completeness of such information.

IN CONNECTION WITH THE OFFERING OF THE 2022 BONDS THE UNDERWRITERS MAY OVERALLOT OR EFFECT TRANSACTIONS THAT STABILIZE OR MAINTAIN THE MARKET PRICE OF THE 2022 BONDS AT LEVELS ABOVE THOSE WHICH MIGHT OTHERWISE PREVAIL IN THE OPEN MARKET. SUCH STABILIZING, IF COMMENCED, MAY BE DISCONTINUED AT ANY TIME.

CAUTIONARY STATEMENTS REGARDING FORWARD-LOOKING STATEMENTS IN THIS OFFICIAL STATEMENT

Certain statements included or incorporated by reference in this Official Statement constitute "forward-looking statements." Such statements are generally identifiable by the terminology used such as "plan," "expect," "estimate," "budget" or other similar words. Such forward-looking statements include, but are not limited to, certain statements contained in the information under the captions "RATE REGULATION" and "CERTAIN FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY" in this Official Statement and in the description of each of the Significant Share Project Participant's operations set forth in APPENDIX A hereto. Forward-looking statements in APPENDIX A and elsewhere in this Official Statement are subject to risks and uncertainties, including particularly those relating to natural gas costs and availability, wholesale and retail electric energy and capacity prices, federal and State legislation and regulations, competition and industry restructuring, the impact of weather on operations and operating results, changes in customer electricity usage patterns, developments associated with the ongoing COVID-19 pandemic, and the economies of the service areas of the Project Participants.

The achievement of certain results or other expectations contained in such forward-looking statements involve known and unknown risks, uncertainties and other factors that may cause actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. NCPA does not plan to issue any updates or revisions to those forward-looking statements if or when its expectations or events, conditions or circumstances on which such statements are based occur.

NCPA maintains a website. However, the information presented therein is not part of this Official Statement and should not be relied upon in making investment decisions with respect to the 2022 Bonds.

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OFFICIAL STATEMENT

NORTHERN CALIFORNIA POWER AGENCY
HYDROELECTRIC PROJECT NUMBER ONE REVENUE BONDS

$________*	**$__________***
2022 Refunding Series A	**2022 Taxable Refunding Series B**

INTRODUCTION

This Introduction is qualified in its entirety by reference to the more detailed information included and referred to elsewhere in this Official Statement. The offering of the 2022 Bonds to potential investors is made only by means of the entire Official Statement. Capitalized terms used in this Introduction and not otherwise defined herein will have the respective meanings assigned to them elsewhere in this Official Statement. See "APPENDIX D–SUMMARY OF CERTAIN PROVISIONS OF THE INDENTURE – Certain Definitions."

Purpose

The purpose of this Official Statement, which includes the cover page and appendices hereto, is to set forth certain information concerning (i) the Northern California Power Agency ("NCPA"); (ii) NCPA's $_________* Hydroelectric Project Number One Revenue Bonds, 2022 Refunding Series A (the "2022 Series A Bonds") and $__________* Hydroelectric Project Number One Revenue Bonds, 2022 Taxable Refunding Series B (the "2022 Series B Bonds" and together with the 2022 Series A Bonds, the "2022 Bonds"); and (iii) the eleven NCPA Members which have entered into the Third Phase Agreement (hereinafter defined) with NCPA (collectively, the "Project Participants") relating to NCPA's Hydroelectric Project Number One (the "Project" or the "Hydroelectric Project"), including in particular the five principal Project Participants (the "Significant Share Project Participants").

The 2022 Bonds are being issued by NCPA for the purpose of providing funds to refund NCPA's Outstanding Hydroelectric Project Number One Revenue Bonds, 2008 Refunding Series A (the "2008 Series A Bonds") and Hydroelectric Project Number One Revenue Bonds, 2012 Series A (the "2012 Series A Bonds" and, together with the 2008 Series A Bonds, the "Refunded Bonds"), and to pay costs of issuance of the 2022 Bonds and other costs related to the refunding of the Refunded Bonds, including costs of termination of an interest rate swap agreement relating to the 2008 Series A Bonds. See "PLAN OF REFUNDING."

NCPA

NCPA is a joint exercise of powers agency formed under the Joint Exercise of Power Act (Cal. Gov. Code §§ 6500 *et seq.*) (the "Act") and an Amended and Restated Northern California Power Agency Joint Powers Agreement (the "NCPA Joint Powers Agreement") now among the City of Alameda ("Alameda"), the City of Biggs ("Biggs"), the City of Gridley ("Gridley"), the City of Healdsburg ("Healdsburg"), the City of Lodi ("Lodi"), the City of Lompoc ("Lompoc"), the City of Palo Alto ("Palo Alto"), the City of Redding ("Redding"), the City of Roseville ("Roseville"), the City of Santa Clara ("Santa Clara"), the City of Shasta Lake ("Shasta Lake"), the City of Ukiah ("Ukiah"), the City of Oakland acting by and through its Board of Port Commissioners ("Port of Oakland"), the Truckee Donner Public Utility District ("Truckee Donner"), and the San Francisco Bay Area Rapid Transit District ("BART") as members, and the Plumas-Sierra Rural Electric Cooperative ("Plumas-Sierra"), as an

* Preliminary, subject to change.

associate member (herein collectively referred to as the "Members" and individually as a "Member"). The Project Participants and their Project Entitlement Percentages are shown on page (a) hereof. The Significant Share Project Participants, representing in aggregate over 90% in Project Entitlement Percentages, are the cities of Alameda, Lodi, Palo Alto, Roseville and Santa Clara.

Authority for Issuance

The 2022 Bonds are being issued pursuant to the provisions of Article 4 of the Act and Articles 10 and 11 of Chapter 3 of Part l of Division 2 of Title 5 of the Government Code of the State of California and under and in accordance with an Indenture of Trust, dated as of March 1, 1985, by and between NCPA and U.S. Bank Trust Company, National Association, as successor trustee (the "Trustee"), as amended and supplemented, including as supplemented by the Twenty-Seventh Supplemental Indenture of Trust, dated as of April 1, 2022 (the "Twenty-Seventh Supplemental Indenture") relating to the 2022 Series A Bonds, and by the Twenty-Eighth Supplemental Indenture of Trust, dated as of April 1, 2022 (the "Twenty-Eighth Supplemental Indenture"), relating to the 2022 Series B Bonds (collectively, the "Indenture"), the Agreement for Construction, Operation and Financing of the North Fork Stanislaus River Hydroelectric Development Project, dated as of September 1, 1982, as amended (the "Third Phase Agreement"), by and among NCPA and the Project Participants, and the Power Purchase Contract dated July 6, 1981, as amended and revised by the Revised Power Purchase Contract, dated as of March 1, 1985 (the "Power Purchase Contract"), by and between NCPA and Calaveras County Water District ("Calaveras").

The 2022 Bonds and all Hydroelectric Project Number One Revenue Bonds Outstanding under the Indenture are referred to herein as the "Hydroelectric Project Bonds."

The Project

The Project consists of a 252.86 megawatt ("MW") hydroelectric project (net capacity based on California Independent System Operator Masterfile for Collierville Powerhouse and Spicer Meadow Dam Powerhouse) and related facilities, described under the caption "THE HYDROELECTRIC PROJECT." NCPA is entitled, under the Power Purchase Contract (i) to receive the electric output, and associated capacity, of the Project for 50 years from February 1982, with an option to purchase Project capacity and energy in excess of Calaveras' requirements thereafter, subject to Federal Energy Regulatory Commission ("FERC") approval, and (ii) to operate the generating facilities of the Project. In February 1990, the operating portions of the Project were declared substantially complete and commercially operable. The Project is primarily used to serve the Project Participants' load requirements, and is secondarily used for load-following by NCPA, whereby the project output is used to balance the Project Participants' load forecast deviations.

Third Phase Agreement

Under the Third Phase Agreement, NCPA has agreed to provide, and each Project Participant has agreed to take or cause to be taken, the Project Participant's Project Entitlement Percentage of the capacity and energy of the Project. The Project Participants pay for such capacity and energy on a cost-of-service basis. Each Project Participant has agreed to make payments for such capacity and energy solely from the revenues of, and as an operating expense of, such Project Participant's electric system. Such payments must be made regardless of whether or not the Project is operable, operating or retired and notwithstanding the suspension, interruption, interference, reduction or curtailment of Project output or the capacity and energy contracted for in whole or in part for any reason whatsoever. See "SECURITY AND SOURCES OF PAYMENT FOR THE 2022 BONDS – Third Phase Agreement."

Security and Sources of Payment for the 2022 Bonds

The 2022 Bonds are special, limited obligations of NCPA. The 2022 Bonds are payable solely from, and secured solely by a pledge and assignment of, the Trust Estate, consisting primarily of the NCPA Revenues, and the other funds pledged by NCPA under the Indenture as described under the caption "SECURITY AND SOURCES OF PAYMENT FOR THE 2022 BONDS."

The 2022 Bonds are not debts, liabilities or obligations of the State of California, any public agency thereof (other than NCPA), any Member of NCPA or any Project Participant and neither the faith and credit nor the taxing power of any of the foregoing (including NCPA) is pledged for the payment of the 2022 Bonds. NCPA has no taxing power.

No Debt Service Reserve Account

No debt service reserve account will be established to secure the 2022 Bonds. Amounts held in or credited to any other debt service reserve account established in connection with any other Series of Outstanding Hydroelectric Project Bonds do not secure, and are not available for, the payment of the 2022 Bonds.

Risk Factors

For a description of certain risks associated with the purchase of the 2022 Bonds, see "SECURITY AND SOURCES OF PAYMENT FOR THE 2022 BONDS – Limitations on Remedies," "RATE REGULATION," "CERTAIN FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY" and "LITIGATION."

Other Matters

The summaries of and references to all documents, statutes, reports and other instruments referred to herein do not purport to be complete, comprehensive or definitive, and each such summary and reference is qualified in its entirety by reference to each document, statute, report or instrument. The capitalization of any word not conventionally capitalized or otherwise defined herein indicates that such word is defined in a particular agreement or other document and, as used herein, has the meaning given to it in such agreement or document. In preparing this Official Statement, NCPA has relied upon certain information relating to the Project Participants furnished to NCPA by the Project Participants.

Attached to this Official Statement is a summary of certain provisions of the Indenture. Copies of the Indenture, the Escrow Agreement, the Third Phase Agreement and the Continuing Disclosure Agreements are available for inspection at the offices of NCPA in Roseville, California, and will be available upon request and payment of duplication costs from the Trustee.

PLAN OF REFUNDING

General

The 2022 Bonds are being issued for the purpose of providing funds to refund all of the Outstanding 2008 Series A Bonds and 2012 Series A Bonds. A portion of the proceeds of the 2022 Bonds will also be applied to pay costs of issuance of the 2022 Bonds and other costs related to the refunding of the Refunded Bonds, including costs of termination of an interest rate swap agreement relating to the 2008 Series A Bonds. **The bonds identified herein for refunding, maturities, dates and amounts are subject to change by NCPA in its sole discretion.**

Prior Financings and Refunding Plan*

Refunded 2008 Series A Bonds. The 2008 Series A Bonds were originally issued on April 2, 2008 in the aggregate principal amount of $85,160,000 pursuant to the Indenture for the purpose of refinancing a portion of the costs of the Project. As of the date hereof, $79,220,000 principal amount of 2008 Series A Bonds remains Outstanding. The Outstanding 2008 Series A Bonds mature on July 1, 2032, with scheduled mandatory sinking fund payments due in each of the years 2022 through 2032. The Outstanding 2008 Series A Bonds will be called for redemption on ________, 2022.

The refunding of the 2008 Series A Bonds is being undertaken by NCPA as part of a plan to refund its Outstanding variable rate Hydroelectric Project Bonds with fixed rate debt and reduce the notional amount of the associated interest rate swap agreement (the hereinafter defined 2008 Series A Hydroelectric Swap) when market conditions so warrant. The 2008 Series A Bonds represent NCPA's only currently Outstanding variable rate Hydroelectric Project Bonds. In connection with the issuance of the 2022 Bonds and the refunding of the 2008 Series A Bonds, the 2008 Series A Hydroelectric Swap (currently outstanding in the notional amount of $_______) is to be terminated in full. Following the termination of such interest rate swap, there will no interest rate swap agreements associated with NCPA's Hydroelectric Project Bonds remaining outstanding.

The following table details the maturity dates and principal amounts of the 2008 Series A Bonds to be refunded (hereinafter, the "Refunded 2008 Series A Bonds").

Refunded 2008 Series A Bonds

Maturity Date (July 1)	CUSIP†	Outstanding Principal Amount to be Refunded	Interest Rate	Redemption Date	Redemption Price
2032[(1)]	664845BE3	$79,220,000	Variable	_______, 2022	100%

(1) Term Bond.

† CUSIP® is a registered trademark of American Bankers Association. CUSIP® data herein are provided by CUSIP Global Services, managed by S&P Global Market Intelligence on behalf of American Bankers Association. Neither NCPA nor the Underwriters is responsible for the selection or correctness of the CUSIP numbers set forth herein.

On the date of delivery of the 2022 Bonds, a portion of the proceeds thereof, together with certain [other available amounts][amounts to be contributed by NCPA] (representing estimated interest to accrue on the Refunded 2008 Series A Bonds at an assumed interest rate of ___% per annum) will be deposited in the respective 2008 Refunding Funds established under the Twenty-Seventh Supplemental Indenture and Twenty-Eighth Supplemental Indenture to be maintained by the Trustee. Moneys deposited in said funds will be applied, together with any investment earnings thereon available for such purpose, as described below.

The redemption of the Refunded 2008 Series A Bonds will be effected by drawing on the letter of credit securing the payment of principal of and interest on such Refunded 2008 Series A Bonds on the redemption date in an amount sufficient to redeem the Refunded 2008 Series A Bonds on the redemption date, at a redemption price equal to 100% of the principal of such Refunded 2008 Series A Bonds, together with accrued interest to the date fixed for redemption, without premium. The proceeds of the 2022 Bonds and other amounts deposited in the 2008 Refunding Funds established for the Refunded 2008

* Preliminary, subject to change.

Series A Bonds will be used on the redemption date of the Refunded 2008 Series A Bonds to reimburse the letter of credit bank, in its capacity as the credit provider for the Refunded 2008 Series A Bonds, for the draw made under the letter of credit. Upon such application, following the redemption date, no Refunded 2008 Series A Bonds will remain outstanding and the letter of credit securing the payment of such Refunded 2008 Series A Bonds will terminate by its terms. See "OTHER OBLIGATIONS OF NCPA."

Refunded 2012 Series A Bonds. The 2012 Series A Bonds were originally issued on February 7, 2012 in the aggregate principal amount of $76,665,000 pursuant to the Indenture for the purpose of refinancing a portion of the costs of the Project. As of the date hereof, $76,665,000 principal amount of 2012 Series A Bonds remains Outstanding. The Outstanding 2012 Series A Bonds mature on July 1 in each of the years 2024 through 2032. The Outstanding 2012 Series A Bonds will be called for redemption on July 1, 2022.

The following table details the maturity dates and principal amounts of the 2012 Series A Bonds to be refunded (hereinafter, the "Refunded 2012 Series A Bonds"). The refunding of the Refunded 2012 Series A Bonds is being undertaken to achieve net present value and debt service savings.

Refunded 2012 Series A Bonds

Maturity Date (July 1)	CUSIP[†]	Outstanding Principal Amount to be Refunded	Interest Rate	Redemption Date	Redemption Price
2024	664845EB6	$ 4,475,000	5.00%	July 1, 2022	100%
2025	664845EC4	11,265,000	5.00	July 1, 2022	100
2026	664845ED2	11,830,000	5.00	July 1, 2022	100
2027	664845EE0	12,425,000	5.00	July 1, 2022	100
2028	664845EF7	13,040,000	5.00	July 1, 2022	100
2029	664845EG5	4,570,000	5.00	July 1, 2022	100
2030	664845EH3	4,800,000	5.00	July 1, 2022	100
2031	664845EJ9	5,040,000	5.00	July 1, 2022	100
2032	664845EK6	9,220,000	5.00	July 1, 2022	100
Total		$76,665,000			

† CUSIP® is a registered trademark of American Bankers Association. CUSIP® data herein are provided by CUSIP Global Services, managed by S&P Global Market Intelligence on behalf of American Bankers Association. Neither NCPA nor the Underwriters is responsible for the selection or correctness of the CUSIP numbers set forth herein.

Pursuant to an Escrow Deposit Agreement (the "Escrow Agreement"), to be entered into by NCPA and U.S. Bank Trust Company, National Association, as Trustee, a portion of the proceeds of the 2022 [Series A] Bonds, together with certain other available funds, will be deposited into an escrow fund (the "2012 Series A Refunding Escrow Fund") and will either be held as cash or will be used to purchase non-callable, direct obligations of, or obligations the principal of and interest on which are unconditionally guaranteed by, the United States of America (the "Escrow Securities") that will bear interest at such rates and will be scheduled to mature at such times and in such amounts so that, when paid in accordance with their respective terms, and together with the cash held in the 2012 Series A Refunding Escrow Fund, sufficient moneys will be available to pay the redemption price (100.0% of the principal amount) of the Refunded 2012 Series A Bonds on the redemption date therefor, together with accrued interest on such Refunded 2010 Series A Bonds.

On the date of delivery of the 2022 Bonds, NCPA will receive a report from ___________, ________, __________, verifying the adequacy of the cash deposited and held in the 2012 Series A Refunding Escrow Fund, together with the maturing principal amounts of and interest earned on the Escrow Securities (if any), to pay on July 1, 2022, the redemption price of the Refunded 2012 Series A Bonds and accrued interest thereon. See “VERIFICATION OF MATHEMATICAL COMPUTATIONS.”

Upon such deposit to the 2012 Series A Refunding Escrow Fund for their payment, the Refunded 2012 Series A Bonds will no longer be deemed to be Outstanding under the Indenture, and all obligations of NCPA with respect to the Refunded 2012 Series A Bonds shall cease and terminate, except for the obligation of NCPA to cause the amounts due on the Refunded 2012 Series A Bonds to be paid from funds on deposit in the 2012 Series A Refunding Escrow Fund.

ESTIMATED SOURCES AND USES OF FUNDS

The estimated sources and uses of funds with respect to the 2022 Bonds and other amounts, rounded to the nearest dollar, are as follows:

	2022 Series A Bonds	2022 Series B Bonds	Total
Sources of Funds			
Principal Amount	$	$	$
Original Issue Premium			
Transfer from Refunded Bonds funds and accounts			
[NCPA Contribution]			
Total	$	$	$
Uses of Funds			
Deposit to 2012 Series A Refunding Escrow Fund	$	$	$
Refunded Series 2008 A Bonds Redemption Amount			
Swap Termination Payment(1)			
Costs of Issuance(2)			
Total	$	$	$

(1) Includes accrued amount payable to the swap termination date.
(2) Costs of issuance include legal, financing and consulting fees, Underwriters’ discount, fees of the verification agent, trustee and escrow agent, rating agency fees, printing costs and other miscellaneous expenses.

OTHER OBLIGATIONS OF NCPA

Each NCPA project is separately financed. As of January 31, 2022, in addition to the $223.3 million Hydroelectric Project Bonds Outstanding under the Indenture (of which [$155.9] million is being refunded by the 2022 Bonds), NCPA had outstanding approximately $13.8 million Capital Facilities Revenue Bonds, $10.8 million outstanding Geothermal Project Number 3 Revenue Bonds and $306.5 million Lodi Energy Center Revenue Bonds. For further information on NCPA projects and related bond issues, see “OTHER NCPA PROJECTS.” Each Project Participant is also a direct or indirect participant in one or more of such other NCPA projects.

In 2004, NCPA entered into an interest rate swap agreement (the "2008 Series A Hydroelectric Swap") with Citigroup Financial Products Inc. ("CFPI") in an initial notional amount of $85.16 million in anticipation of refunding $85.87 million principal amount of NCPA's then Outstanding 1998 Bonds (the "1998 Bonds"). Certain of the 1998 Bonds were refunded with the issuance of NCPA's variable rate 2008 Series A Bonds. Pursuant to the 2008 Series A Hydroelectric Swap, the floating rate interest payments that NCPA is obligated to make with respect to the 2008 Series A Bonds were converted into substantially fixed rate payments. In general, the terms of the 2008 Series A Hydroelectric Swap provide that, on a same-day net-payment basis determined by reference to a notional amount equal to the principal amount of the Outstanding 2008 Series A Bonds (*i.e.*, $79.2 million), NCPA will pay a fixed interest rate on the notional amount. In return, CFPI will pay a variable rate of interest under the 2008 Series A Hydroelectric Swap on a like notional amount. The agreement by CFPI to make payments under the 2008 Series A Hydroelectric Swap does not affect NCPA's obligation to make payment of the 2008 Series A Bonds. Under certain circumstances, the 2008 Series A Hydroelectric Swap is subject to termination and NCPA may be required to make a substantial termination payment to the counterparty thereunder. Payments due from NCPA under the 2008 Series A Hydroelectric Swap, including any amounts payable upon early termination thereof, are insured by National Public Finance Guarantee Corporation (formerly MBIA Insurance Corporation). As described above, the 2008 Series A Hydroelectric Swap is being terminated on the redemption date for the Refunded 2008 Series A Bonds in connection with the issuance of the 2022 Bonds and the refunding of the Refunded 2008 Series A Bonds on such redemption date. See "PLAN OF REFUNDING."

The 2008 Series A Bonds are variable rate obligations secured by a letters of credit, upon which the Trustee and tender agent, as applicable, under the Indenture, are entitled to draw to pay the principal or redemption price of, and interest on, the 2008 Series A Bonds, and to pay the purchase price of 2008 Series A Bonds which are tendered but are not successfully remarketed. The existing letter of credit for the 2008 Series A Bonds has been provided by Bank of America, N.A. and has a scheduled expiration date of June 21, 2024. As described above, the letter of credit for the 2008 Series A Bonds will terminate by its terms upon the redemption of the Refunded 2008 Series A Bonds. See "PLAN OF REFUNDING."

THE 2022 BONDS

The following is a summary of certain provisions of the 2022 Bonds. Reference is made to the Indenture for a more detailed description of such provisions. The discussion herein is qualified by such reference.

General

The 2022 Bonds of each Series are being issued in the respective aggregate principal amounts indicated on the inside cover page of this Official Statement. The 2022 Bonds of each Series will mature on July 1 in the years and in the amounts, and will bear interest at the rates per annum, as shown on the inside cover page of this Official Statement. The 2022 Bonds of each Series will be dated their date of delivery. Interest on the 2022 Bonds of each Series is payable on January 1 and July 1 of each year, commencing [July 1, 2022] (calculated on the basis of a 360-day year comprised of twelve 30-day months).

The 2022 Bonds are being issued in fully registered form, and, when issued, will be registered in the name of Cede & Co., as nominee for The Depository Trust Company, New York, New York ("DTC"), such registered owner of 2022 Bonds being hereinafter referred to as the "Holder." DTC will act as securities depository for the 2022 Bonds. Ownership interests in the 2022 Bonds may be purchased in book-entry form only. Ownership interests in the 2022 Bonds of each Series may be purchased in authorized denominations of $5,000 and any integral multiple thereof. Purchasers will not receive securities certificates representing their interests in the 2022 Bonds purchased. Payments of principal of, premium, if any, and interest on the 2022 Bonds is payable by the Trustee to DTC, which is obligated in turn to remit such principal, premium, if any, and interest to its DTC Participants for subsequent disbursement to the beneficial owners of the 2022 Bonds. See "APPENDIX C–BOOK-ENTRY ONLY SYSTEM."

Redemption of 2022 Bonds

Optional Redemption

2022 Series A Bonds. The 2022 Series A Bonds are not subject to optional redemption prior to their respective stated maturity dates.

2022 Series B Bonds. The 2022 Series B Bonds are subject to redemption prior to their stated maturity dates, at the option of NCPA, in whole or in part, in such amounts as may be specified by NCPA, on any date, from any source of available funds, at a redemption price equal to 100% of the principal amount of such 2022 Series B Bonds plus the Make-Whole Premium (as defined below), if any, plus unpaid accrued interest, if any, thereon to the redemption date.

The "Make-Whole Premium" with respect to any 2022 Series B Bond to be redeemed will be equal to the positive difference, if any, between:

(1) the sum of the present values, calculated as of the date fixed for redemption of: (a) each interest payment that, but for such redemption, would have been payable on the 2022 Series B Bonds or portion thereof being redeemed on each regularly scheduled interest payment date occurring after the dated fixed for redemption through the maturity date of the 2022 Series B Bonds (excluding any accrued interest for the period prior to the redemption date); provided, that if the date fixed for redemption is not a regularly scheduled interest payment date with respect to such 2022 Series B Bonds, the amount of the next regularly scheduled interest payment will be reduced by the amount of the interest accrued on such 2022 Series B Bond to the date fixed for redemption, plus (b) the principal amount that, but for such redemption, would have been payable at the final maturity of the 2022 Series B Bonds or portion thereof being redeemed; minus

(2) the principal amount of the 2022 Series B Bonds or portion thereof being redeemed.

The present values of interest and principal payments referred to in paragraph (1) above will be determined by discounting the amount of each interest or principal payment from the date that each such payment would have been payable, but for the redemption to the date fixed for redemption on a semiannual basis (assuming a 360-day year consisting of twelve 30-day months) at a discount rate equal to the "comparable treasury yield" (as defined below) plus ___ basis points.

The Make-Whole Premium will be calculated by an independent investment banking institution or independent financial advisor of national standing appointed by NCPA.

For purposes of determining the Make-Whole Premium, "comparable treasury yield" means a rate of interest per annum equal to the weekly average yield to maturity for the preceding week appearing in the most recently published statistical release designated "H.15(519) Selected Interest Rates" under the heading "Treasury Constant Maturities," or any successor publication that is published weekly by the Board of Governors of the Federal Reserve System and that establishes yields on actively traded United States Treasury securities adjusted to constant maturity, for the maturity corresponding to the remaining term to maturity of the 2022 Series B Bonds ("the H.15 statistical release"). The comparable treasury yield will be determined as of the third business day immediately preceding the applicable redemption date. If the H.15 statistical release sets forth a weekly average yield for United States Treasury Securities having a constant maturity that is the same as the remaining term calculated as set forth above, then the comparable treasury yield will be equal to such weekly average yield. In all other cases, the comparable treasury yield will be calculated by interpolation on a straight-line basis, between the weekly average yields on the United States Treasury Securities (in each case as set forth in the H.15 statistical release) that have a constant maturity (i) closest to and greater than the remaining term to maturity of the 2022 Series B Bonds being redeemed; and (ii) closest to and less than the remaining term to maturity of the 2022 Series B Bonds being redeemed. Any weekly average yields calculated by interpolation will be rounded to the nearest 1/100th of 1%, with any figure of 1/200th of 1% or above being rounded upward.

If, and only if, weekly average yields for United States Treasury securities for the preceding week are not available in the H.15 statistical release, then the comparable treasury yield will be the rate of interest per annum equal to the semiannual equivalent yield to maturity of the Comparable Treasury Issue (expressed as a percentage of its principal amount) equal to the Comparable Treasury Price (each as defined herein) as of the date fixed for redemption.

"Comparable Treasury Issue" means the United States Treasury security selected by the independent investment banking institution or independent financial advisor of national standing appointed by NCPA as having a maturity comparable to the remaining term to maturity of the 2022 Series B Bond being redeemed that would be utilized, at the time of selection and in accordance with customary financial practice, in pricing new issues of corporate debt securities of comparable maturity to the remaining term to maturity of the 2022 Series B Bond being redeemed.

"Comparable Treasury Price" means, with respect to any date on which a 2022 Series B Bond or portion thereof is being redeemed, either (a) the average of five Reference Treasury Dealer quotations for the date fixed for redemption, after excluding the highest and lowest such quotations, and (b) if the independent investment banking institution or independent financial advisor of national standing appointed by NCPA is unable to obtain five such quotations, the average of the quotations that are obtained. The quotations will be the average, as determined by the independent investment banking institution or independent financial advisor of national standing appointed by NCPA, of the bid and asked prices for the Comparable Treasury Issue (expressed in each case as a percentage of principal amount) quoted in writing to the independent investment banking institution or independent financial advisor of national standing appointed by NCPA, at 5:00 p.m. New York City time on the third business day preceding the date fixed for redemption.

"Reference Treasury Dealer" means a primary United States Government securities dealer in the United States appointed by NCPA (which may be an Underwriter) and reasonably acceptable to the independent investment banking institution or independent financial advisor of national standing appointed by NCPA.

Extraordinary Redemption

The 2022 Bonds are subject to redemption prior to their respective stated maturity dates, at the option of NCPA, in whole or in part (in such amounts as may be specified by NCPA) on any date, from: (i) insurance or condemnation proceeds and (ii) from any source of money if all or substantially all of the Initial Facilities are damaged or destroyed, taken by any public entity in the exercise of its powers of eminent domain or disposed of or abandoned, at a redemption price equal to the principal amount thereof, plus unpaid accrued interest to the date fixed for redemption, without premium; provided that the option of NCPA to call the 2022 Bonds for redemption from insurance or condemnation proceeds will expire 90 days following the receipt of such insurance or condemnation proceeds.

Selection of 2022 Bonds for Redemption

NCPA may select the Series of the 2022 Bonds, the maturities of the 2022 Bonds and the principal amount of each such maturity to be redeemed in its sole discretion. Whenever provision is made in the Indenture for the redemption of less than all of the 2022 Bonds of like maturity of any Series, the Trustee will select the 2022 Bonds to be redeemed from all 2022 Bonds of such Series and maturity subject to redemption and not previously called for redemption, at random in any manner which the Trustee in its sole discretion may deem appropriate and fair.

Notice of Redemption

The Indenture requires the Trustee to give notice of the redemption of any 2022 Bonds by mailing a notice of redemption of such 2022 Bonds, postage prepaid, not less than 30 days before the redemption date, to the Holders of any 2022 Bonds or portions of 2022 Bonds which are to be redeemed, at their last address appearing upon the registry books. Among other things, such notice will state that on the redemption date there will become due and payable on each 2022 Bond to be redeemed the redemption price thereof, or the redemption price of the specified portions of the principal thereof in the case of 2022 Bonds to be redeemed in part only, together with unpaid accrued interest to the redemption date, and that on and after such date, interest thereon will cease to accrue and be payable. Receipt of such notice will not be a condition precedent to such redemption and failure so to receive such notice or any defect in such notice will not affect the validity of the proceedings for the redemption of 2022 Bonds. So long as the 2022 Bonds are in book-entry form, such notice of redemption by the Trustee to the Holders will be mailed only to DTC (or its nominee).

SECURITY AND SOURCES OF PAYMENT FOR THE 2022 BONDS

Pledge Effected by the Indenture

The 2022 Bonds are special, limited obligations of NCPA payable solely from, and secured solely by a pledge and assignment of, the following pursuant to the Indenture, which constitutes the Trust Estate: (a) subject only to the provisions of the Indenture permitting the application thereof for the purposes and on the terms and conditions set forth therein, (i) the proceeds of the sale of the Hydroelectric Project Bonds, (ii) (a) all revenues, income, rents and receipts derived or to be derived by NCPA from or attributable to the Project or the Power Purchase Contract or to the payment of the costs of the Project received or to be received by NCPA under the Third Phase Agreement or the Power Purchase Contract or under any other contract for the sale by NCPA of the Project or any part thereof or any contractual arrangement with respect to the use of the Project or any portion thereof or the services or capacity thereof, (b) the proceeds of any insurance, including the proceeds of any self-insurance fund, covering business interruption loss relating to the Project, and (c) interest received or to be received on any moneys or securities (other than in the Construction Fund) held pursuant to the Indenture and required to be paid into the Revenue Fund established thereunder ("NCPA Revenues"), and (iii) all amounts on deposit in the Funds established by the Indenture, including the investments, if any, thereof to the extent held by the Trustee and (b) all right, title and interest of NCPA in, to and under the Third Phase Agreement and the Power Purchase Contract.

The 2022 Bonds and the interest thereon are payable solely from the funds provided therefor under the Indenture and will not constitute a charge against the general credit of NCPA. The 2022 Bonds are not secured by a legal or equitable pledge of, or lien or charge upon, any property of NCPA or any of its income or receipts except the Trust Estate pledged pursuant to the

Indenture which is subject to the provisions of the Indenture permitting the application thereof for the purposes and on the terms and conditions set forth therein. Neither the faith and credit nor the taxing power of the State of California or any public agency thereof or any Member of NCPA or any Project Participant is pledged to the payment of the principal of, or interest on, the 2022 Bonds. NCPA has no taxing power. Neither the payment of the principal of, or interest on, the 2022 Bonds constitutes a debt, liability or obligation of the State of California or any public agency thereof (other than NCPA) or any Member of NCPA or any Project Participant. The Commissioners, directors, officers and employees of NCPA will not be individually liable on the 2022 Bonds or in respect of any undertakings by NCPA under the Indenture.

The 2022 Bonds are payable from and secured by the Trust Estate on a parity basis with all other Hydroelectric Project Bonds Outstanding under the Indenture. As of January 31, 2022, there was $223.2 million aggregate principal amount of Hydroelectric Project Bonds Outstanding under the Indenture (of which [$155.9] million is being refunded by the 2022 Bonds).

Order of Application of NCPA Revenues

Pursuant to the Indenture, all NCPA Revenues received are to be deposited promptly in the Revenue Fund upon receipt thereof. Amounts in the Revenue Fund are to be paid monthly in the following order of priority for application therefrom as follows:

[Remainder of page intentionally left blank.]

Revenue Fund

- *First* → Operating Reserve Fund(1)
- *Second* → Operating Fund(2)
- *Third* → Debt Service Fund
  - Debt Service Account
  - Debt Service Reserve Account(3)
  - Series Debt Service Reserve Accounts
- *Fourth* → Subordinated Indebtedness Fund(4)
- *Fifth* → Note Fund(5)
- *Sixth* → Reserve and Contingency Fund(6)
  - Renewal and Replacement Account
  - Reserve Account
- *Seventh* → General Reserve Fund(7)
  - Rate Stabilization Account
  - General Account

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(1) To be maintained in such amount as recommended by a Consulting Engineer. The Consulting Engineer has recommended that such amount be set to $0, provided that NCPA has established a common special reserve fund for the operating and maintenance expenses of the Project and the NCPA Geothermal Project in an amount not less than $3,000,000. Such special reserve has been established.

(2) To be applied for the payment of NCPA Operating Expenses.

(3) The Debt Service Reserve Account is maintained in an amount equal to the Debt Service Reserve Requirement as defined in APPENDIX D. Amounts in the Debt Service Reserve Account are available to fund deficiencies in the Debt Service Account for Participating Bonds. The 2022 Bonds are Non-Participating Bonds and are not secured by amounts in the Debt Service Reserve Account. See "SECURITY AND SOURCES OF PAYMENT FOR THE 2022 BONDS – No Debt Service Reserve Account for 2022 Bonds." NCPA's Outstanding NCPA's Hydroelectric Project Number One Revenue Bonds, 2008 Refunding Series A, 2012 Refunding Series A, 2012 Taxable Refunding Series B, 2018 Refunding Series A, and 2019 Refunding Series A are not Participating Bonds. The Indenture provides that Future Bonds will be Participating Bonds unless otherwise provided in the Supplemental Indenture authorizing such Future Bonds. Future Bonds may be supported by amounts in a Series Debt Service Reserve Account established for such Future Bonds or may be issued with no debt service reserve. The 2022 Bonds are being issued with no debt service reserve.

(4) To be applied to the payment of Subordinated Indebtedness under the Indenture. There is currently no Subordinated Indebtedness Outstanding under the Indenture.

(5) To be applied to the payment of Notes. There are currently no Notes Outstanding under the Indenture.

(6) Amounts in the Renewal and Replacement Account (currently $0) are to be applied to the costs of Capital Improvements. The Reserve Account is to be maintained in such amount as recommended by the Consulting Engineer. Amounts in the Reserve Account, if any, are to be applied to the costs of Capital Improvements not funded from the Renewal and Replacement Account, to the payment of extraordinary operating and maintenance costs of the Project and to contingencies. Amounts in the Reserve and Contingency Fund, if any (currently $0) are available to fund deficiencies in Operating Fund or Debt Service Fund.

(7) Amounts in the General Reserve are to be applied to make up deficiencies in the Debt Service Account, the Debt Service Reserve Account and the Reserve and Contingency Fund, and may be applied, upon a determination of NCPA, for other specified purposes, including any other lawful purpose of NCPA related to the Project.

See "APPENDIX D–SUMMARY OF CERTAIN PROVISIONS OF THE INDENTURE" for further discussion of certain of the terms and provisions of the Indenture relating to the application of NCPA Revenues.

NCPA Rate Covenant

Pursuant to the Indenture, NCPA has covenanted, at all times, to establish and collect rates and charges with respect to the Project to provide NCPA Revenues at least sufficient in each Fiscal Year, together with other available funds, for the payment of all of the following: (i) NCPA Operating Expenses, (ii) Aggregate Debt Service, (iii) all other required deposits to any Funds under the Indenture, and (iv) all other charges or other amounts whatsoever payable out of NCPA Revenues during such Fiscal Year. See "APPENDIX D–SUMMARY OF CERTAIN PROVISIONS OF THE INDENTURE – Covenants – Rate Covenant."

No Debt Service Reserve Account for 2022 Bonds

No debt service reserve account will be established to secure the 2022 Bonds.

Pursuant to the Indenture, certain prior Series of Hydroelectric Project Bonds were secured by, and all future Series of Hydroelectric Project Bonds other than Hydroelectric Project Bonds authorized by a Supplemental Indenture that provides that such Hydroelectric Project Bonds are not "Participating Bonds" will be secured by, the Debt Service Reserve Account. The Indenture provides that a Supplemental Indenture authorizing a Series of Hydroelectric Project Bonds may provide that such Hydroelectric Project Bonds are not Participating Bonds (all such Hydroelectric Project Bonds being referred to as "Non-Participating Bonds") and may be secured by a Series Debt Service Reserve Account or may be issued with no debt service reserve. Pursuant to the Twenty-Seventh Supplemental Indenture and Twenty-Eighth Supplemental Indenture, respectively, the 2022 Series A Bonds and 2022 Series B Bonds are not Participating Bonds and each such Series will be issued with no debt service reserve. Amounts on deposit in any Series Debt Service Reserve Account for any Series of Non-Participating Bonds shall be used and withdrawn as provided in the Supplemental Indenture authorizing the issuance of such Non-Participating Bonds. Amounts on deposit in the Debt Service Reserve Account secure only Participating Bonds and do not secure in any manner the 2022 Bonds. Amounts on deposit in any Series Debt Service Reserve Account for any other Series of Non-Participating Bonds do not secure in any manner the 2022 Bonds.

See "APPENDIX D–SUMMARY OF CERTAIN PROVISIONS OF THE INDENTURE – Debt Service Reserves for Future Bonds."

Additional Hydroelectric Project Bonds

NCPA may issue Hydroelectric Project Bonds under and secured by the Indenture to refund bonds previously issued and Outstanding under and secured by the Indenture and may, although it does not currently expect to, issue Additional Bonds to finance Capital Improvements to the Project. For further information, see "APPENDIX D–SUMMARY OF CERTAIN PROVISIONS OF THE INDENTURE – Additional Bonds" and "– Refunding Bonds."

Third Phase Agreement

Project Participants' Take-or-Pay Obligation. The Third Phase Agreement authorizes NCPA to fix charges thereunder equal to the amounts anticipated to be needed to provide capacity and energy from the Project, including but not limited to debt service, operation, maintenance and replacement costs, a reasonable reserve for contingencies, and all other costs of the Project. The Third Phase Agreement further provides that, to the extent that the funds provided thereunder and described in the preceding sentence are not sufficient for such purposes, the Project Participants will pay an amount equal to their Project Entitlement Percentage of debt service on bonds, notes and other evidences of indebtedness (including an applicable percentage of the 2022 Bonds), reserves therefor, and all other payments required to be made under the Indenture and the Power Purchase Contract, whether or not the Project is completed, operable, operating or retired and notwithstanding the suspension, interruption, interference, reduction or curtailment of Project output or the power and energy contracted for in whole or in part for any reason whatsoever.

Operating Expense. Each Project Participant will make payments under the Third Phase Agreement solely from the Revenues of, and as an operating expense of, its electric system. Nothing in the Third Phase Agreement prohibits any Project Participant from using any other funds and revenues to satisfy the provisions thereof.

Project Participants' Rate Covenant. Each Project Participant agrees to establish and collect fees and charges for electric capacity and energy furnished through facilities of its electric system sufficient to provide Revenues adequate to meet its obligations under the Third Phase Agreement and to pay any and all other amounts payable from or constituting a charge and lien upon any or all such Revenues.

Increase in Non-defaulting Project Participants' Original Project Entitlement Percentage. Upon the failure of any Project Participant to make any payment, which failure constitutes a default under the Third Phase Agreement, and except as sales and transfers are made pursuant thereto, the Third Phase Agreement provides that the Project Entitlement Percentage of each non-defaulting Project Participant will be automatically increased for the remaining term of the Third Phase Agreement, pro rata with those of the other non-defaulting Project Participants thereunder; provided, however, that the sum of such increases for any non-defaulting Project Participant will not exceed, without written consent of such non-defaulting Project Participant, an accumulated maximum of 25% of the non-defaulting Project Participant's original Project Entitlement Percentage.

Transfer, Sale or Assignment. Each Project Participant has the right to make transfers, sales and/or assignments of its interests in Project capacity and energy and rights thereto; provided that no such transfer, sale or assignment shall adversely affect the tax-exempt status of interest on Hydroelectric Project Bonds issued under the Indenture. No such transfer, sale or assignment shall relieve the Project Participant of its obligations under the Third Phase Agreement. No Project Participant shall transfer its electric system unless the Project Participant provides assurance that its obligations under the Third Phase Agreement will be promptly and adequately met, including providing sufficient moneys for such purpose if no other adequate assurance is available.

Limitations on Remedies

The rights of the owners of the 2022 Bonds are subject to the limitations on legal remedies against cities and other public agencies in the State. Additionally, enforceability of the rights and remedies of the owners of the 2022 Bonds, and the obligations incurred by the NCPA and the Project Participants, may become subject to the following: the Federal Bankruptcy Code and applicable bankruptcy, insolvency, reorganization, moratorium, or similar laws relating to or affecting the enforcement of creditor's rights generally, now or hereafter in effect; equity principles which may limit the specific enforcement under State law of certain remedies; the exercise by the United States of America of the powers delegated to it by the Constitution; and the reasonable and necessary exercise, in certain exceptional situations, of the police powers inherent in the sovereignty of the State and its governmental bodies in the interest of serving a significant and legitimate public purpose. Bankruptcy proceedings, or the exercise of powers by the federal or State government, if initiated, could subject the owners of the 2022 Bonds to judicial discretion and interpretation of their rights in bankruptcy or otherwise, and consequently may entail risks of delay, limitation, or modification of their rights.

NORTHERN CALIFORNIA POWER AGENCY

Background

NCPA is a joint exercise of powers agency formed under the Act and the NCPA Joint Powers Agreement now among Alameda, Biggs, Gridley, Healdsburg, Lodi, Lompoc, Oakland (acting by and through its Board of Port Commissioners), Palo Alto, Redding, Roseville, Santa Clara, Shasta Lake, Ukiah, Truckee Donner, and BART as members, and Plumas-Sierra, as an associate member (herein collectively referred to as the "Members" and individually as a "Member").

Under the terms of the NCPA Joint Powers Agreement entered into by all Members, NCPA possesses the general powers to acquire, purchase, generate, transmit, distribute and sell electrical capacity and energy. Specific powers include the power to enter into contracts, acquire and construct electric generating facilities, set rates, issue revenue bonds and notes and acquire property by eminent domain.

The Facilities Agreement, originally executed by the NCPA Members in 1993, and superseded by the Amended and Restated Facilities Agreement, dated as of October 1, 2014 (the "Facilities Agreement"), provides for the development of all projects undertaken by NCPA in three separate phases: (i) the initial phase of general investigation funded by NCPA's general fund; (ii) the second phase whereby Members of NCPA electing to participate in the project execute a project agreement to provide for the cost of development of the project (now referred to as an "NCPA Project"); and (iii) the third phase during which all remaining aspects, including financing, construction and operation of the NCPA Project are undertaken. Pursuant to the Facilities Agreement and NCPA's other governing member services agreements, NCPA's administrative, general and occupancy costs and expenses, including costs and expenses of the employees of NCPA (including salaries, wages and retirement benefits), are paid by NCPA Members based on an agreed upon cost allocation methodology.

Members of NCPA have no financial or other responsibility or liability associated with the acquisition, construction, maintenance, operation or financing of any NCPA project pursuant to the NCPA Joint Powers Agreement. Members become obligated for payments with respect to a NCPA project only as participants with respect to such project as set forth in an agreement with NCPA separate from the NCPA Joint Powers Agreement.

NCPA has supplied many services to its Members in the past and expects to continue to do so in the future. NCPA has been instrumental in litigating and negotiating with Pacific Gas and Electric Company ("PG&E"), the California Independent System Operator (the "CAISO") and the Western Area Power Administration of the federal government ("Western") to keep wholesale power and transmission and other ancillary services rates at levels which have resulted in substantial savings when compared to rates sought by each of those suppliers. It is anticipated that NCPA will continue to litigate and/or negotiate on behalf of its Members to maintain rates at levels which will result in continued advantage to its Members.

NCPA's audited financial statements for the fiscal years ended June 30, 2021 and 2020 are attached as APPENDIX B.

Organization and Management

NCPA's governing body (the "Commission") is composed of one representative from each Member, each such representative being designated a Commissioner. The Commission is given the general management of the affairs, property and business of NCPA and is vested with all powers of NCPA. Under the NCPA Joint Powers Agreement, associate Members do not have a voting seat on the Commission, except as may be provided in a project agreement.

The management of NCPA is responsible for various areas of administration and planning of NCPA's operations and affairs. The overall management is under the direction of NCPA's General Manager, who serves at the discretion of the Commission. NCPA is organized into four separate divisions: (i) generation services, (ii) power management, (iii) legislative and regulatory, and (iv) administrative services.

Set forth below is a brief biography of each of NCPA's senior managers.

RANDY S. HOWARD, General Manager, was appointed General Manager of NCPA in January 2015. Prior to accepting the position at NCPA, Mr. Howard was the Senior Assistant General Manager of the Power System at Los Angeles Department of Water and Power ("LADWP"). Mr. Howard has held previous LADWP positions as Executive Director of Customer Services, Director of Power System Planning and Development, and the Chief Compliance Officer in the Power System Executive Office. Mr. Howard is currently leading NCPA forward with several major strategic initiatives to address member issues and opportunities. Mr. Howard presents frequently before governance bodies, including the NCPA Board, and local, State and federal agencies on issues of importance to utilities. Mr. Howard has held many previous engineering and customer service management positions at LADWP. Mr. Howard has an undergraduate degree in Electrical Engineering from California State University, Sacramento and a master's degree in Business Administration from Pepperdine University.

JANE E. LUCKHARDT, Esq., General Counsel, joined NCPA on May 1, 2017. Ms. Luckhardt received her Juris Doctorate from Stanford Law School, and her Bachelor of Science degree in Construction Management from California Polytechnic State University, San Luis Obispo, California. Prior to joining NCPA, Ms. Luckhardt was a partner at the boutique energy law firm of Day Carter Murphy LLP and previously at Downey Brand, LLP, where she served in several leadership roles including Assistant to the Managing Partner, Executive Committee Member and Practice Group Leader for the Energy, Land Use and Mining Practice Group. Ms. Luckhardt also serves as the Vice President of the Power Association of Northern California, an energy trade group located in San Francisco, California. Ms. Luckhardt writes and speaks on issues facing the energy industry for energy trade groups and at legal conferences.

MONTY HANKS, Assistant General Manager, Finance/Administrative Services, Chief Financial Officer received his master's degree in Business Administration and a Bachelor of Science degree in Business Administration (Finance concentration) from California State University, Sacramento. Mr. Hanks has over 25 years of financial experience, including experience working with an electric, water, wastewater and solid waste utilities. Before joining NCPA in February 2017, Mr. Hanks was employed by the City of Roseville for 15 years serving in the role of Finance Director. At NCPA, Mr. Hanks oversees the Administrative Services division which includes finance, accounting, power settlements, information technology, human services, risk management and facilities management.

JANE DUNN CIRRINCIONE, Assistant General Manager, Legislative and Regulatory, received a master's degree in Public Administration from the University of Southern California, and a Bachelor of Science degree in Political Science from the University of Santa Clara and the London School of

Economics. Ms. Cirrincione has over 30 years of experience in the energy and environmental policy arena. Prior to joining NCPA, she was a Senior Government Relations Representative for the American Public Power Association ("APPA") in Washington, D.C. APPA is the national trade association representing the country's over 2,000 public power systems. Before joining APPA, she was the Director of Legislative Programs for the National Hydropower Association, representing all sections of the U.S. hydroelectric industry. She also spent several years on Capitol Hill as a Legislative Assistant for Congressman Don Edwards working on environmental and wildlife issues impacting the San Francisco Bay. Before moving to Washington, D.C., she worked for the U.S. Fish and Wildlife Service at the Sacramento National Wildlife Refuge. Ms. Cirrincione was the 2018 recipient of the APPA Harold Kramer/John Preston Personal Service Award recognizing contributions toward the advancement of the association's goals and the interests of public power. Ms. Cirrincione chairs the Transmission Access Policy Study Group—a national organization of public power systems focused on federal legislative and regulatory issues impacting the power grid. She is also a member of the APPA's PowerPAC Board of Directors.

TONY ZIMMER, Assistant General Manager, Power Management, has been employed by Northern California Power Agency (NCPA) since July 2000. Mr. Zimmer received a Master's degree in Business Administration, and a Bachelor of Science degree in Finance from the California State University, Sacramento. Mr. Zimmer's experience includes contract development and negotiation, policy and procedure development, resource development and integration, settlements, scheduling and operational coordination, interconnection affairs, business development, CAISO market design and advocacy, and data analysis and system design. Mr. Zimmer currently manages the Power Management division at NCPA, including the scheduling coordination and dispatch functions, power pool operations, portfolio management activities, interconnection affairs, regulatory activities associated with the NCPA power pool and CAISO operations. Mr. Zimmer is a member of NCPA's Risk Oversight Committee.

RANDY BOWERSOX, Assistant General Manager, Generation Services, joined NCPA in June 2007. Mr. Bowersox received a master's degree in Business Administration, a master's degree in Civil & Environmental Engineering, and a Bachelor of Science degree in Electrical Engineering from the University of California, Davis. At NCPA, Mr. Bowersox directs and coordinates NCPA's generation facilities, which are located throughout Northern California and encompass 13 different generating units including geothermal, hydroelectric, aero derivative gas, and combined cycle power plants with combined generation of approximately 800 megawatts. Mr. Bowersox has previously held the NCPA positions of Hydroelectric Plant Manager and Chief Dam Safety Engineer. Prior to joining NCPA, Mr. Bowersox worked as an engineering consultant and project manager at Carlton Engineering, advising a variety of energy, industrial, and land development clients.

NCPA Power Pool

NCPA operates a power pool that includes the following Members: Alameda, Biggs, Gridley, Healdsburg, Lodi, Lompoc, Palo Alto, Plumas Sierra, the Port of Oakland and Ukiah (each, an "NCPA Pool Member"). The ten NCPA Pool Members' service areas are interconnected to the CAISO-controlled grid. NCPA operates a central dispatch facility (the "Central Dispatch Center") at NCPA's headquarters. The Central Dispatch Center balances loads and resources pursuant to the Third Amended and Restated NCPA Metered Subsystem Aggregation Agreement (the "MSSA"), as such may be amended from time to time, with the CAISO (as described below) for the ten NCPA Pool Members, and Santa Clara. The Central Dispatch Center separately coordinates with Roseville to schedule Roseville's entitlement to the Project output across the CAISO-controlled grid as requested by Roseville. The Central Dispatch Center also monitors and controls load and voltage levels of the Project, and enters into buy and sell transactions with other utilities throughout the western United States and Canada and regulates various hydroelectric facilities in coordination with the CAISO to maintain a safe and reliable interconnected system.

NCPA operates according to the terms and conditions of the CAISO tariff and the MSSA, the original form of which was approved by FERC in 2002 and as has been amended and restated as needed from time to time to conform to applicable market rules established by the CAISO and FERC. The MSSA identifies operational terms and conditions that vary from the CAISO tariff, largely allowing NCPA Members to continue to operate their respective systems as vertically integrated utilities by generally self-providing for resources and services otherwise procured through the CAISO's markets. In conjunction with the execution of the MSSA, NCPA and PG&E are parties to an Interconnection Agreement (the "NCPA-PG&E Interconnection Agreement") that provides for the terms and conditions for connecting NCPA resources and member loads to the CAISO-controlled grid (or PG&E wholesale transmission system), where such CAISO-controlled grid facilities are owned by PG&E and transferred to CAISO operational control through a Transmission Control Agreement between PG&E and the CAISO.

Santa Clara has separate agreements for the services provided under the MSSA and NCPA-PG&E Interconnection Agreement. See "APPENDIX A–SELECTED INFORMATION RELATING TO THE SIGNIFICANT SHARE PROJECT PARTICIPANTS – CITY OF SANTA CLARA."

Wholesale Power Trading and Other Activities

NCPA trades in the Western wholesale electricity markets to maximize the value of its transmission and generation assets and to minimize its cost of power supply for its Members. NCPA has engaged in wholesale market transactions since 1984. See also "LITIGATION – California Energy Market Dysfunction, Refund Dispute and Related Litigation" for certain information regarding past disruptions and related disputes arising in such markets following the partial deregulation of the electricity markets pursuant to AB 1890 enacted in 1996 and subsequent developments.

In addition to the wholesale energy market services NCPA supplies to its Members, NCPA also provides a variety of wholesale energy market services, including wholesale power trading, to certain non-Member customers. Currently, NCPA provides various scheduling, operating, and portfolio management services to Merced Irrigation District, Nevada Irrigation District and Placer County Water Agency, as well as to three community choice aggregators ("CCAs"): East Bay Community Energy, San Jose Clean Energy, and Sonoma Clean Energy. Such services are provided on a fee-for-service basis. NCPA has made an effort to identify and mitigate any potential counterparty risks in its service agreements with the non-Member entities to which it provides wholesale energy market services. NCPA only carries liability to the extent of NCPA's insurance coverage. In addition, NCPA requires these customers to deposit an amount equal to the highest three months of estimated CAISO invoices into a security account held by NCPA.

Investment of NCPA Funds

All funds of NCPA (except bond proceeds which are invested pursuant to the indenture under which such bonds are issued, pension funds, and other post-employment benefit funds) are invested in accordance with NCPA's investment policy and guidelines (the "Investment Policy") as authorized by Sections 53600 et seq. of the Government Code of the State of California. The Investment Policy is reviewed by NCPA's Finance Committee and approved by the NCPA Commission. The NCPA Commission approves monthly activity reports.

The following securities, if and to the extent the same are at the time legal and in compliance with the applicable bond covenants and agreements for investment of NCPA's funds, are authorized investments under the Investment Policy: (i) securities of the U.S. Government, or its agencies, (ii) certificates of deposit (or time deposits) placed with commercial banks and/or savings and loan companies, (iii) negotiable certificates of deposit, (iv) bankers acceptances, (v) Local Agency Investment

Fund (State Pool) demand deposits, (vi) repurchase agreements, (vii) passbook savings account demand deposits, (viii) municipal bonds, (ix) commercial paper, (x) medium term corporate notes, and (xi) California Asset Management Program (CAMP).

The Investment Policy provides the following guidelines, among others. All rated securities must be rated by a nationally recognized statistical rating organization (NRSRO) as "Category A" or its equivalent or better. All certificates of deposit must mature within five years. The portfolio will be diversified with holdings from at least several of the major eligible market sectors. Except for obligations issued or guaranteed by the U.S. Government, federal agencies or government-sponsored corporations, the Local Agency Investment Fund and the California Asset Management Program, no more than 10% of an NCPA construction project or of the NCPA operating funds portfolio will be invested in the securities of any one issuer. Unless otherwise restricted, all holdings will be of sufficient size and held in issues which are actively traded to facilitate transactions at a minimum cost and accurate market valuation. Buying and selling securities before settlement or the use of reverse repurchase agreements for speculative purposes is not authorized. A reverse repurchase agreement may be used only in infrequent circumstances and only to prevent a material loss that would otherwise result from the sale of an investment for liquidity purposes. Any reverse repurchase agreements must be specifically reported to the Commission along with the reasons therefor on a timely basis.

The Investment Policy may be changed at any time at the discretion of the Commission subject to the State law provisions relating to authorized investments. Any exception to the Investment Policy must be formally approved by the Commission. There can be no assurance, therefore, that the State law and/or the Investment Policy will not be amended in the future to allow for investments which are currently not permitted under such State law or the Investment Policy, or that the objectives of NCPA with respect to investments will not change.

THE HYDROELECTRIC PROJECT

The Project consists of (a) three diversion dams, (b) the 246.86-MW Collierville Powerhouse, (c) the Spicer Meadow Dam with a 6.0-MW powerhouse, and (d) associated tunnels located essentially on the North Fork Stanislaus River in Alpine, Tuolumne and Calaveras Counties, California, together with required transmission and related facilities. The peak generating capacity of the Project is approximately 253 MW.

The Project, with the exception of certain transmission facilities, is owned by Calaveras and is licensed by FERC, pursuant to a 50-year License (Project No. 2409) issued in 1982 to Calaveras. Pursuant to the Power Purchase Contract, NCPA (i) is entitled to the electric output, including capacity, of the Project until February 2032, (ii) managed the construction of the Project, and (iii) operates the generating and recreational facilities of the Project. Under a separate FERC-issued license with an expiration date coterminous with the Project No. 2409 license (Project No. 11197), NCPA holds the license and owns the 230 kV Collierville-Bellota and the 21 kV Spicer Meadows-Cabbage Patch transmission lines for Project No. 2409. NCPA also has a separate FERC license for Project No. 11563 (Upper Utica Project), which consists of three storage reservoirs that mainly feed the New Spicer Meadow Reservoir. This license expires in 2033. *Northern California Power Agency*, 104 F.E.R.C. ¶ 62,163 (2003). After the present FERC License for Project No. 2409 expires in the year 2032, NCPA has the option to continue to purchase Project capacity and energy during a subsequent license renewal period. It is currently estimated that the price will be significantly less than the comparable alternatives at that time. The purchase option includes all capacity and energy which is surplus to Calaveras' needs for power within the boundaries of Calaveras County.

As with any hydroelectric generation project, the operation of the Project is determined by consideration of its storage capacity, hydrology conditions, and available stream flows and requirements. Based upon historical hydrology conditions and demonstrated generation, the Project's average production is estimated to be approximately 493 GWh annually. The Project is optimized together with NCPA's other resources as determined by NCPA, to economically meet the load requirements of the respective Project Participants. The load-following characteristics of the Project gives NCPA a great degree of flexibility in meeting the hourly and daily variations which occur in the Project Participants' loads. The net Project generation for the previous ten fiscal years is as follows:

Fiscal Year Ended June 30	Total Net Generation (GWh)
2012	463
2013	268
2014	197
2015	164
2016	397
2017	945
2018	487
2019	852
2020	442
2021	203

The reduced generation in the fiscal year ended June 30, 2021 reflects ongoing drought conditions. The average generating capacity for such fiscal year was 26 MW.

NCPA financed the Project through the issuance of Hydroelectric Project Number One Revenue Bonds, of which approximately $223.2 million aggregate principal amount was Outstanding as of January 31, 2022. See "Indebtedness" for each of the Significant Share Project Participants in "APPENDIX A–SELECTED INFORMATION RELATING TO THE SIGNIFICANT SHARE PROJECT PARTICIPANTS" for a discussion of the obligations of each of the Significant Share Project Participants with respect to the Project.

NCPA has sold the energy and capacity of the Project to the Project Participants pursuant to a "take-or-pay" power sales contract, which require payments to be made whether or not the project is completed or operable. Each purchaser is responsible under the power sales contract for paying its entitlement share in the Project of all of NCPA's costs of the Project, including debt service on the aforementioned bonds as well as a "step-up" of up to 25% in the event of the unremedied default of another Project Participant.

Biggs and Gridley have transferred their entitlement shares of the Project output to Santa Clara. Each Project Participant remains obligated for all payments due from such Project Participant under the Third Phase Agreement, in the event moneys received from transferees pursuant to such arrangements are insufficient to satisfy all payments. Redding, Truckee Donner, Port of Oakland, Shasta Lake and BART, which are Members of NCPA, are not Project Participants, and have no financial or other responsibility or liability associated with the acquisition, construction, maintenance, operation or financing of the Project.

THE PROJECT PARTICIPANTS

General

The Project Participants and their Project Entitlement Percentages are shown on page (a) of this Official Statement.

The governing body of each Project Participant has approved the Third Phase Agreement. The California Public Utilities Code authorizes the municipal Project Participants to "acquire...any public utility," including the supply of light and power. In furtherance of such powers, a municipal corporation "may acquire...rights of every nature...when necessary to supply the municipality, or its inhabitants or any portion thereof, with the service desired."

Members of NCPA have no financial or other responsibility or liability associated with the acquisition, construction, maintenance, operation or financing of a particular project other than as project participants with respect to such project as set forth in the related third phase agreement.

Descriptions of the Significant Share Project Participants

The five Project Participants with the largest Project Entitlement Percentages are Alameda (10.00%), Lodi (10.37%), Palo Alto (22.92%), Roseville (12.00%) and Santa Clara (35.86%), which, in the aggregate, comprise over 90% of the Project. None of the remaining Project Participants has a Project Entitlement Percentage in excess of 3%. Alameda, Lodi, Palo Alto, Roseville, and Santa Clara are sometimes referred to herein as the "Significant Share Project Participants." Brief descriptions of the Significant Share Project Participants, their service areas, existing power supply resources, customers, energy sales and revenues and expenses are set forth in "APPENDIX A–SELECTED INFORMATION RELATING TO THE SIGNIFICANT SHARE PROJECT PARTICIPANTS."

Electric Systems

Each Project Participant owns and operates an electric system for distribution of electric power and energy together with the general plant necessary to conduct its business. The electric systems of some of the Project Participants are among the oldest electric utilities in operation in California and some predate the existence of PG&E. The electric systems were founded during the period from 1887 to 1937. The Project Participants are all experienced in operating electric distribution systems.

All of the Project Participants provide, through NCPA projects, for a portion of their own power needs. In addition, Alameda, Healdsburg, Lodi, Lompoc, Roseville and Ukiah obtain a portion of their power needs from Western. Biggs, Gridley, Palo Alto and Plumas-Sierra are also wholesale customers of Western and obtain a larger portion of their power needs from that source. Roseville also derives a portion of its power from its own generating facilities. Santa Clara receives part of its power requirements from Western, part from other power agencies, the power markets and its own generating projects. NCPA also purchases power from the market for certain of its Members (the Project Participants, exclusive of Santa Clara and Roseville) for periods of up to 30 days and for periods of up to five years (under separate project agreements) for Biggs, Gridley, Healdsburg, Lodi, Lompoc and Ukiah. Delivery of all such power is made over the CAISO-controlled grid, the Balancing Area of Northern California ("BANC"), Western transmission facilities, the California-Oregon Transmission Project ("COTP") or combinations of those transmission facilities and balancing areas.

Service Areas

The municipal Project Participants provide retail electric service within their service areas pursuant to the authority of the Constitution of the State of California, Article XI, Section 9. Under California law, the municipal Project Participants have authority to acquire, construct, establish, enlarge, improve, maintain, own and operate electric distribution systems. Plumas-Sierra provides electric service pursuant to its Articles and Bylaws.

The retail customers of the municipal Project Participants are located within their respective city boundaries and environs. Plumas-Sierra serves rural areas in Plumas, Lassen and Sierra Counties in California and in Washoe Township in Washoe County, Nevada.

OTHER NCPA PROJECTS

Set forth below is a brief description of the NCPA resources in addition to the Project. Each such resource is financed under a separate agreement with the Members participating in such resource. No Member not a party to such agreement has any obligation to make payments in connection with such resources.

Participating Members occasionally make short-term and long-term assignments of entitlement rights to NCPA resources. Such assignment would not impact the underlying project participant obligations contained in the applicable agreement relating to such NCPA resource and each project participant remains obligated for all payments due from such project participant in the event moneys received from transferees pursuant to such arrangements are insufficient to satisfy all payments.

Lodi Energy Center Project

NCPA owns and operates a natural gas-fired, combined-cycle power generation plant located in the City of Lodi, San Joaquin County, California (the "Lodi Energy Center" or "LEC"). The electric generation components (the "Power Island") of the Lodi Energy Center consists of the following components: (1) one natural gas-fired Siemens STG6-5000F combustion turbine-generator (CTG), with an evaporative cooling system and dry low-NOx combustors to control air emissions; (2) one 3-pressure heat recovery steam generator (HRSG), (3) a selective catalytic reduction (SCR) and carbon monoxide ("CO") catalyst to further control NOx and CO emissions, respectively; (4) one Siemens SST-900RH condensing steam turbine generator ("STG"); (5) one natural gas-fired auxiliary boiler; (6) one 7-cell draft evaporative cooling tower; and (7) associated support equipment. The Lodi Energy Center was placed into commercial operation on November 27, 2012.

LEC is currently registered with a Pmax of 302 MW (increased from 280 MW in 2018). (The Pmax is a measure of the maximum normal capability of a generating unit that is utilized by the CAISO in determining the amount of capacity that can be counted toward meeting resource adequacy requirements.) NCPA intends to conduct further testing of the LEC facility in 2022 to increase the Pmax further as a result of transmission reconductoring completed by PG&E in 2018. LEC net generation for the last five fiscal years has been as follows:

Fiscal Year Ended June 30	LEC Net Generation (GWhs)
2016-17	301
2017-18	1,075
2018-19	1,382
2019-20	866
2020-21	1,232

The reduced generation in the fiscal year ended June 30, 2017 was directly attributable to the increase in PG&E gas transportation costs. NCPA negotiated a special rate for gas transmission for LEC which went into effect during Fiscal Year 2017-18. PG&E's 2023 gas transmission rate case that will set rates for the period 2023 to 2026 is currently ongoing. LEC is operating as expected in the current fiscal year. NCPA and PG&E have negotiated gas transportation rates that are in effect through December 2022. The reduced generation in the fiscal year ended June 30, 2020 reflects an outage from mid-January through mid-June 2020 due to a turbine failure.

Pursuant to the Lodi Energy Center Power Sales Agreement (the "LEC Power Sales Agreement"), by and among NCPA and (i) the NCPA Member project participants: Biggs, Gridley, Healdsburg, Lodi, Lompoc, Plumas-Sierra, Santa Clara, Ukiah and BART; and (ii) the non-NCPA Member project participants: the City of Azusa, the Modesto Irrigation District, the Power and Water Resources Pooling Authority and the California Department of Water Resources ("CDWR") (all such entities other than NCPA, collectively the "LEC Project Participants"), NCPA agreed to construct and operate the Lodi Energy Center and has sold the capacity and energy of the Lodi Energy Center to the thirteen LEC Project Participants on a "take-or-pay" basis, in accordance with their respective generation entitlement shares to the capacity and energy of the Lodi Energy Center.

NCPA financed a portion a portion of the Lodi Energy Center construction costs through the issuance of revenue bonds: (i) its Lodi Energy Center Revenue Bonds, Issue One, issued on behalf of eleven of the thirteen participants in the Lodi Energy Center (being all of the above-named LEC Project Participants other than the Modesto Irrigation District and CDWR), of which $206.9 million is outstanding as of January 31, 2022, and (ii) its Lodi Energy Center Revenue Bonds, Issue Two, issued on behalf of CDWR, of which $99.6 million is outstanding as of January 31, 2022. The Modesto Irrigation District provided its own financing for its share of the estimated costs of construction of the Lodi Energy Center. See "Indebtedness" for each of the Significant Share Project Participants in "APPENDIX A– SELECTED INFORMATION RELATING TO THE SIGNIFICANT SHARE PROJECT PARTICIPANTS" for a discussion of the obligations of each of Lodi and Santa Clara with respect to the Lodi Energy Center Project.

The Lodi Energy Center is operated and maintained by NCPA under the general direction of the LEC Project Participants pursuant to the LEC Power Sales Agreement and the Lodi Energy Center Project Management and Operations Agreement among NCPA and the LEC Project Participants.

Geothermal Project

NCPA has developed a geothermal project (the "Geothermal Project") located on federal land in certain areas of Sonoma and Lake Counties, California (the "Geysers Area"). In addition to the geothermal leasehold, wells, gathering system and related facilities, the Geothermal Project consists of two electric generating stations (Plant 1 and Plant 2), with combined 165 MW (nameplate rating) turbine generator units utilizing low pressure, low temperature geothermal steam, associated electrical, mechanical and control facilities, a heat dissipation system, a steam gathering system, a transmission tapline and other related facilities. Geothermal steam for the project is derived from the geothermal property, which includes wellpads, access roads, steam wells and reinjection wells. NCPA formed two not-for-profit corporations controlled by its Members to own the generating plants of the Geothermal Project. NCPA manages the Geothermal Project for the corporations and is entitled to all the capacity and energy generated by the Geothermal Project.

As noted above, the Geothermal Project consists of two operating electric generating stations (Plant 1 and Plant 2), where Plant 1 contains two 55 MW (nameplate rating) turbine generator units, and Plant 2 contains one 55 MW (nameplate rating) turbine generator unit. Plant 1 and Plant 2 were originally developed and operated as separate projects referred to as "Geothermal Project Number 2" and "Geothermal Project Number 3," respectively. Plant 1 became operational in 1983 and Plant 2 became operational in 1986. Plant 1 and Plant 2 are now operated together as the Geothermal Project pursuant to the terms of the Amended and Restated Geothermal Operating Agreement.

Steam for NCPA's geothermal plants comes from lands in the Geysers Area, which are leased by NCPA from the federal government. NCPA operates these steam-supply areas. Operation of the geothermal plants at high generation levels, together with high steam usage by others in the same area, resulted in a decline in the steam production from the steam wells at a rate greater than expected. As a result, starting in 1988, NCPA has been taking steps to reduce the rate of steam production decline. NCPA entered into agreements with other geothermal operators in the Geysers Area to finance and construct the Southeast Geysers Effluent Pipeline Project, which was completed in September 1997 and began operating soon thereafter. The 26-mile pipeline collects wastewater from Lake County Sanitation District treatment plants at Clearlake and Middletown and delivers the wastewater to NCPA and the other Geysers steam field operator for injection into the steam field. In 2021, NCPA received approximately 31% of the wastewater for reinjections from this effluent pipeline.

NCPA has also implemented and continues to implement various operating strategies and modifications to further reduce the rate of decline in steam production. NCPA has modified all of the steam turbines and the associated steam collection system to enable generation with lower pressure steam and increased conversion efficiencies of the available steam resource.

Average annual generation of the Geothermal Project was approximately 108 MW gross ("MWG") for calendar year ("CY") 2021. Based on current operating protocols and forecasted operations, after CY 2021, the peak capacity is expected to continue to decrease, reaching approximately 106 MW in CY 2022 and 76 MWG by CY 2040. Under terms of the federal geothermal leasehold agreements, which became effective August 1, 1974, the leasehold had a 10-year primary term with provision for renewal as long thereafter as geothermal steam is produced or utilized, but not longer than 40 years. At the expiration of that period, if geothermal steam is still being produced, NCPA has preferential right to renew the leasehold for a second term. In 2013, NCPA renewed the leasehold. The leasehold also requires NCPA to remove its leasehold improvements including the geothermal plants and steam gathering system when and if NCPA abandons the leasehold. Based upon a decommissioning costs study obtained by NCPA in December 2016, these decommissioning costs are currently estimated to total approximately $67.8 million. NCPA has been collecting monies to pay the expected decommissioning costs since 2007 and holds $24.6 million in a designated reserve for such purpose as of June 30, 2021. Collections towards future decommissioning costs are expected to be approximately $1.7 million for Fiscal Year 2021-22.

Each of the Significant Share Project Participants, together with Biggs, Gridley, Healdsburg, Lompoc, Ukiah and Plumas Sierra, along with non-NCPA Member Turlock Irrigation District, participate in the Geothermal Project. NCPA has sold the capacity and energy of the Geothermal Project to the

Geothermal Project participants on a "take-or-pay" basis, in accordance with their respective project entitlement percentages to the capacity and energy of the Geothermal Project. NCPA financed the Geothermal Project with Geothermal Project Number 3 Revenue Bonds, of which $10.8 million were outstanding as of January 31, 2022. See "Indebtedness" for each of the Significant Share Project Participants in "APPENDIX A–SELECTED INFORMATION RELATING TO THE SIGNIFICANT SHARE PROJECT PARTICIPANTS" for a discussion of the obligations of each of the Significant Share Project Participants with respect to the Geothermal Project.

Geysers Transmission Project

In order to meet certain obligations required of NCPA to secure transmission and other support services for the Geothermal Project, NCPA has undertaken a geysers transmission project (the "Geysers Transmission Project") with the Geysers Transmission Project participants. The Geysers Transmission Project includes (i) a co-tenancy interest in PG&E's 230 kV line from Castle Rock Junction in Sonoma County to the Lakeville Substation (the "Castle Rock to Lakeville Line"), (ii) additional firm transmission rights in the Castle Rock to Lakeville Line and (iii) the Central Dispatch Facility. The transmission line has a combined rated capacity of 1,206 MW held by four co-tenants including: PG&E, with a 931 MW interest; CDWR, with a 165 MW interest; NCPA, with a 50 MW interest; and Santa Clara, with a 60 MW interest). Through a long-term layoff agreement with CDWR, NCPA has the ability to use an additional 24 MW of this transmission facilities' capacity for the life of the asset. CDWR has recently filed notice to terminate its participation in the project, but has yet to reach agreement with the other co-tenants on how to terminate their long-term layoff agreement. NCPA and Santa Clara hold sufficient capacity on the 230 kV transmission line for the current output of the Geothermal Project without including the layoff agreement with CDWR. Nonetheless, NCPA anticipates that once the co-tenants resolve the issues surrounding CDWR's exit from the co-tenancy, NCPA will hold in addition to its initial capacity of 50 MW an additional 8 to 31.4 MW of capacity. NCPA expects this issue to be resolved through arbitration in the next year.

NCPA financed the Geysers Transmission Project through the issuance of Transmission Project Number One Revenue Bonds, which bonds were retired as of August 15, 2010. Alameda, Lodi, Palo Alto and Roseville, together with Biggs, Gridley, Healdsburg, Lompoc, Ukiah and Plumas Sierra, are participants in the Geysers Transmission Project.

Capital Facilities Project

The NCPA Capital Facilities Project, known as Combustion Turbine Project Number Two, currently consists of one power generating station, Unit One, with a design rating of 49.9 MW located in the City of Lodi. Such power generating station consists of a single natural gas-fired steam injected gas turbine (STIG), generator, and required auxiliary and electrical interconnection systems.

The Cities of Alameda, Lodi, Lompoc and Roseville are the project participants in the Capital Facilities Project. NCPA has sold the capacity and energy of the Capital Facilities Project to the Capital Facilities Project participants on a "take-or-pay" basis, in accordance with their respective project entitlement percentages to the capacity and energy of the Capital Facilities Project. NCPA financed the Capital Facilities Project with Capital Facilities Revenue Bonds, of which approximately $13.8 million were outstanding as of January 31, 2022. See "Indebtedness" for each of the Significant Share Project Participants in "APPENDIX A–SELECTED INFORMATION RELATING TO THE SIGNIFICANT SHARE PROJECT PARTICIPANTS" for a discussion of the obligations of each of Alameda, Lodi and Roseville with respect to the Capital Facilities Project.

Unit One is economically dispatched and sold into the CAISO market, supporting grid reliability and market demand.

Combustion Turbine Project Number One

The Combustion Turbine Project Number One (the "Combustion Turbine Project") originally consisted of five combustion turbine units, each nominally rated 25 MW, with two units located in each of Roseville and Alameda and one in Lodi. Sale of the two units located in Roseville to the City of Roseville (an original participant in the Combustion Turbine Project) was effective on September 1, 2010, and the remaining Combustion Turbine Project includes only the two units in Alameda and the one unit in Lodi.

The Combustion Turbine Project provides capacity (i) that is economically dispatched during the peak load period to the extent permitted by air quality restrictions and (ii) to be used to meet the certain capacity reserve requirements (*e.g.*, resource adequacy requirements). This resource provides the capacity below current spot market prices for capacity but as is typical of this type of technology, the average cost for power per kWh of power delivered to the participants in the Combustion Turbine Project is comparatively expensive.

Alameda, Lodi and Santa Clara, together with Healdsburg, Lompoc, Ukiah and Plumas-Sierra, are the current participants in Combustion Turbine Project Number One. NCPA has sold the capacity and energy of the Combustion Turbine Project to the Combustion Turbine Project participants on a "take-or-pay" basis, in accordance with their respective project entitlement percentages to the capacity and energy of the Combustion Turbine Project. NCPA financed the Combustion Turbine Project through the issuance of Combustion Turbine Project Number One Revenue Bonds, which bonds were retired as of August 15, 2010.

Natural Gas Supply Contracts

NCPA, on behalf of the project participants of Combustion Turbine Project and of the Capital Facilities Project's Unit One, has entered into a Master Transaction Confirmation that is appended to and made part of a Base Contract for Sale and Purchase of Natural Gas (the "Consolidated Natural Gas Agreement"), effective on October 30, 2012, with EDF Trading North America, LLC ("EDF"). The Consolidated Natural Gas Agreement provides gas supply and management services, including the following:

- Supply of spot market gas for the full daily output of Combustion Turbine Project Number One and Unit One of the Capital Facilities Project (approximately 35,136 MMBtu/day); and

- Scheduling, nomination, balancing and settlement services for NCPA gas supplies from third parties.

The contract with EDF automatically renews each year on January 1, unless terminated earlier by six months written notice by either party.

Pursuant to a 30-year agreement terminating in October 2023 with various natural gas pipeline management companies, NCPA has entitlement rights to natural gas pipeline capacity of approximately 2,743 MMBtu/day sourced at AECO (Alberta) and sinking at PG&E Citygate (California). The four pipeline segments that are included in the contiguous pipeline entitlement include pipeline contained in the following natural gas systems: NOVA Gas Transmission Ltd. (NOVA), Foothills Pipelines (Foothills), Gas Transmission Northwest (GTN), and PG&E's CGT (CGT). NCPA's natural gas pipeline rights are managed by Mercuria Energy America, Inc., pursuant to an Asset Management Agreement for Pipeline Transport Capacity dated January 1, 2015. For release of such natural gas pipeline to Mercuria Energy America, Inc., NCPA is paid the value of the unused pipeline capacity by the pipeline manager.

In addition, NCPA and EDF entered into an agreement to provide the gas supply and the nomination, imbalance and settlement services for NCPA's Lodi Energy Center, which became effective on September 1, 2016. See " – Lodi Energy Center Project" above.

Power Purchase and Natural Gas Contracts

Henwood Power Purchase Agreement. NCPA, on behalf of Alameda, entered into a power purchase agreement with Henwood Associates, Inc. for 440 kW of capacity and energy. The energy source for the facility is hydroelectric and the facility meets the qualifying facilities requirements, established by FERC. The facility output, which varies with hydrological conditions, has averaged about 2,000 megawatt hours ("MWhs") per year. Deliveries under the agreement began February 1, 2010 and will terminate on January 31, 2030.

Antelope Expansion Power Purchase Agreement. NCPA, on behalf of Biggs, Gridley, Healdsburg, Lodi and Port of Oakland, entered into a power purchase agreement with Antelope Expansion 1B, LLC, for a 33.78%, or approximately 17 MW, share of the output of the Antelope Expansion Phase 1 solar facility. The facility is a 51 MW photovoltaic plant under development in the City of Lancaster, Los Angeles County, California. The facility is expected to reach commercial operation in April 2022. The term of the power purchase agreement is 20 years.

South Feather Power Project Power Purchase Agreement. NCPA, on behalf of Healdsburg, Lodi, Lompoc, Roseville, Santa Clara and Ukiah, Port of Oakland, and the San Francisco Bay Area Rapid Transit District, entered into a power purchase agreement with South Feather Water and Power Agency to purchase output supplied from the South Feather Power Project, an approximately 121 MW hydroelectric project consisting of four (4) powerhouses. The initial delivery term under the power purchase agreement began on December 19, 2021 and will continue for an initial period of 10 years, with an option to extend the term of the agreement for a total term of up to 20 years.

Market Purchase Program. NCPA, on behalf of Alameda, BART, Biggs, Gridley, Healdsburg, Lodi, Lompoc and Ukiah may enter into supply agreements for terms of up to five years utilizing Commission approved Edison Electric Institute and WSPP Inc. Purchase Agreements. Procurement terms and conditions are governed by a Market Purchase Program agreement between NCPA and the participating Members listed in the preceding sentence. Purchase amounts are limited to 115% of each participating members forecast net open position associated with the period of the procurement. The Program was approved by the NCPA Commission on July 26, 2007.

Natural Gas Program. NCPA, on behalf of Biggs, Gridley, Healdsburg, Lodi, Lompoc and Ukiah may enter into gas supply agreements using competitive bids submitted in response to a NCPA Request For Proposals ("RFP Process"), or through direct purchases from the State of California Department of General Services Natural Gas Services Program. Procurement terms and conditions are governed by a Natural Gas Program agreement between NCPA and the participating Members identified in the preceding sentence. Purchases are subject to limits as may be changed from time to time as outlined in the NCPA Energy Risk Management Policy and/or Regulations. The Natural Gas Program was approved by the NCPA Commission on March 24, 2011.

NCPA Services Agreements

BART Services Agreement. NCPA provides power supply and scheduling services to BART pursuant to a Single Member Services Agreement which was executed on December 1, 2005 (as amended from time to time). Under this agreement, NCPA procures power to meet BART's power supply needs utilizing Commission approved Edison Electric Institute and WSPP Inc. Purchase Agreements.

Non-Member Customer Services Agreements. NCPA, pursuant to individual Services Agreements, supplies a variety of wholesale energy market services to non-member customers, including, but not limited to, scheduling services, operating services, and portfolio management services. NCPA is currently providing non-member services to the Merced Irrigation District, Placer County Water Agency, Nevada Irrigation District, East Bay Community Energy, San Jose Clean Energy, and Sonoma Clean Power, under Services Agreements that extend for varying terms. See "NORTHERN CALIFORNIA POWER AGENCY – Wholesale Power Trading and Other Activities."

RATE REGULATION

Each Project Participant and NCPA sets rates, fees and charges for electric service. The authority of the Project Participants or NCPA to impose and collect rates and charges for electric power and energy sold and delivered is not subject to the general regulatory jurisdiction of the California Public Utilities Commission ("CPUC") and presently neither the CPUC nor any other regulatory authority of the State of California nor FERC approves such rates and charges. Although the retail rates of the Project Participants and NCPA are not subject to approval by any federal agency, the Project Participants and NCPA are subject to certain ratemaking provisions of the Federal Public Utility Regulatory Policies Act of 1978 ("PURPA") and Sections 211-213 of the Federal Power Act ("FPA"). It is possible that future legislative and/or regulatory changes could subject the rates and/or service areas of the Project Participants or NCPA to the jurisdiction of the CPUC or to other limitations or requirements.

FERC could potentially assert jurisdiction over rates of licensees of hydroelectric projects and customers of such licensees under Part I of the FPA, although it has not as a practical matter exercised or sought to exercise such jurisdiction to modify rates that would legitimately be charged. If it did assert such jurisdiction, the result might have some significance for NCPA and its Project Participants.

Under provisions of the FPA, FERC has the authority, under certain circumstances and pursuant to certain procedures, to order any utility (municipal or otherwise) to provide transmission access to others at FERC-approved rates. In addition, the Energy Policy Act of 2005 expanded FERC's jurisdiction to require municipal utilities that sell more than eight million MWhs of energy per year to pay refunds under certain circumstances for sales into organized markets. To date, neither NCPA nor any of the Project Participants meet this threshold requirement.

The California Energy Commission (the "CEC") is authorized to evaluate rate policies for electric energy as related to the goals of the Energy Resources Conservation and Development Act and to make recommendations to the Governor, the Legislature and publicly owned electric utilities.

CONSTITUTIONAL LIMITATIONS IN CALIFORNIA AFFECTING FEES AND CHARGES

The following is a discussion of certain limitations under provisions of the California Constitution that may affect the rates, fees and charges imposed by the Project Participants for the electric services they provide.

Proposition 218 and Proposition 26

Proposition 218, a State ballot initiative known as the "Right to Vote on Taxes Act," was approved by the voters of the State of California on November 5, 1996. Proposition 218 added Articles XIIIC and XIIID to the State Constitution. Article XIIIC imposes a majority voter approval requirement on local governments (including the Project Participants) with respect to taxes for general purposes, and a two-thirds voter approval requirement with respect to taxes for special purposes. Article XIIID creates additional requirements for the imposition by most local governments of general taxes, special taxes, assessments and "property-related" fees and charges. Article XIIID explicitly exempts fees for the provision of electric service from the provisions of such article.

Article XIIIC expressly extends the people's initiative power to the reduction or repeal of local taxes, assessments, and fees and charges imposed prior to its effective date (November 1996). The California Supreme Court held in *Bighorn-Desert View Water Agency v. Verjil*, 39 Cal.4th 205 (2006) that, under Article XIIIC, local voters by initiative may reduce a public agency's water rates and delivery charges, as those are property-related fees or charges within the meaning of Article XIIID, and noted that the initiative power described in Article XIIIC may extend to a broader category of fees and charges than the property-related fees and charges governed by Article XIIID. Moreover, in the case of *Bock v. City Council of Lompoc*, 109 Cal.App.3d 52 (1980), the Court of Appeal determined that an electric rate ordinance was not subject to the same constitutional restrictions that are applied to the use of the initiative process for tax measures so as to render it an improper subject of the initiative process. Thus, electric service charges (which are expressly exempted from the provisions of Article XIIID) may be subject to the initiative provisions of Article XIIIC, thereby subjecting such fees and charges to reduction by the electorate. NCPA and the Project Participants believe that even if the electric rates of the Project Participants are subject to the initiative power, under Article XIIIC or otherwise, Article XIIIC does not grant to the electorate of a Project Participant the power to repeal or reduce its electric rates and charges in a manner that would be inconsistent with the contractual obligations of the Project Participant (including those under the Third Phase Agreement).

The California electorate approved Proposition 26 at the November 2, 2010 election, amending Article XIIIC of the California Constitution. Proposition 26 was designed to supplement tax limitations California voters adopted when they approved Proposition 13 in 1978, and Proposition 218 in 1996. Proposition 26 applies by its terms to any levy, charge or exaction imposed, increased or extended by a local government on or after November 3, 2010. Proposition 26 deems any such levy, charge or fee to be a "tax", requiring voter approval under Article XIIIC unless it comes within one of the listed exceptions. Proposition 26 expressly excludes from its definition of a "tax," among other things, a "charge imposed for a specific government service or product provided directly to the payor that is not provided to those not charged, and which does not exceed the reasonable costs to the local government of providing the service or product." Proposition 26 is applicable to the electric rates of governmental entities such as the Project Participants; therefore, newly adopted rates must conform to its requirements.

Proposition 26 is subject to interpretation by California courts, including the extent to which it is applicable to pre-existing electric rates and general fund transfers. A number of lawsuits have been filed against public agencies in California, including particularly with respect to electric utility fund transfers. Palo Alto, one of the Significant Share Project Participants, is currently engaged in litigation filed against the city, generally alleging that the annual transfer of funds from the electric utility to the City of Palo Alto's general fund is an unauthorized tax for purposes of Article XIIIC of the California Constitution in violation of Proposition 26. See "APPENDIX A–SELECTED INFORMATION RELATING TO THE SIGNIFICANT SHARE PROJECT PARTICIPANTS – CITY OF PALO ALTO – Litigation."

Other Initiatives

Articles XIIIC and XIIID and the amendments effected thereto by Proposition 26 were adopted as measures that qualified for the ballot pursuant to California's initiative process. From time to time, including presently, other initiatives have been, and could be, proposed, and if qualified for the ballot, could be enacted which place limitations on the ability of NCPA and/or the Project Participants to raise rates or otherwise affect NCPA's and/or the Project Participants revenues or operations. Neither the nature and impact of these measures nor the likelihood of qualification for ballot or passage can be anticipated by NCPA and the Project Participants.

CERTAIN FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY

The following discussion of legislative, regulatory and other factors affecting the electric utility industry should be considered when evaluating NCPA, the Project and the Project Participants and considering an investment in the 2022 Bonds. NCPA is unable to predict what impact such factors will have on the business operations and/or financial condition of any individual Project Participant or whether any additional legislation or rules will be enacted which will affect NCPA, the Project or the Project Participant's finances or operations, but the impacts could be significant. This discussion does not purport to be comprehensive or definitive, and these matters are subject to change subsequent to the date hereof. Extensive information on the electric utility industry is available from the legislative and regulatory bodies and other sources in the public domain, and potential purchasers of the 2022 Bonds should obtain and review such information. Such information is not incorporated herein by reference.

State Legislation and Regulatory Proceedings

California energy policy is driven by the State's goal to reduce carbon emissions to 80% below 1990 levels by the year 2050. Current State law requires California to reduce emissions to 40% below 1990 levels by 2030. NCPA, the Project Participants and the electric utility industry are subject to a myriad of clean energy policies that regulate greenhouse gas ("GHG") emissions, providing for greater investment in energy efficiency and environmentally friendly generation and storage alternatives, principally through more stringent renewable resource portfolio standard requirements and more aggressive emissions reduction programs to combat the effects of climate change. Recently enacted legislation has also focused on addressing issues relating to wildfire risks and occurrences in California, including imposing certain requirements on electric utilities in connection with planning for and mitigation of such occurrences and risks. Pursuant to enacted legislation, State regulatory agencies such as the California Air Resources Board ("CARB") and the CEC are also pursuing several programs designed to reduce GHG emissions and encourage or mandate renewable energy generation. Set forth below is a brief summary of certain of these activities.

California Climate Program. The State's climate program was initially codified by Assembly Bill 32, the Global Warming Solutions Act of 2006 (the "GWSA"), which became effective on January 1, 2007. The GWSA prescribed a statewide cap on global warming pollution with a goal of returning to 1990 GHG emission levels by 2020. The GWSA established an annual mandatory reporting requirement for all investor-owned utilities ("IOUs"), POUs, and other load-serving entities (electric utilities providing energy to end-use customers) to inventory and report greenhouse gas emissions to CARB, required CARB to adopt regulations for significant greenhouse gas emission sources, allowing CARB to design a "cap-and-trade" program (discussed below) and gave CARB the authority to enforce such regulations beginning in 2012.

Currently, the policy objectives of California's climate program is governed by Senate Bill 32 ("SB 32"), signed into law in September 2016 and effective as of January 1, 2017. SB 32 requires CARB to take actions to ensure that statewide GHG emissions from within the State are reduced to at least 40% below 1990 levels by 2030.

In addition, Senate Bill 350 ("SB 350"), the Clean Energy and Pollution Reduction Act of 2015, required CARB, in consultation with the CPUC and the CEC, to establish 2030 GHG emission targets for each electric utility in the State. At present, these targets are non-binding, and primarily intended to help the State measure progress toward the 2030 statewide goal outlined in SB 32. The targets, however, are an input to the development of the Integrated Resource Plans that are required of the State's 16 largest local publicly-owned electric utilities ("POUs"), which include the four largest NCPA member systems (Santa Clara, Roseville, Redding, and Palo Alto). See "*–Integrated Resource Plans (IRP)*" below.

Cap-and-Trade Program. CARB has adopted a series of regulations implementing a cap-and-trade program (the "Cap-and-Trade program"). The Cap-and-Trade program is the most significant component of the State climate program that impacts electric utilities. Under the program, all regulated entities are required to obtain and submit to CARB compliance instruments (allowances and/or offsets) with respect to GHG emissions relating to its State generation activities, as well as for imported electricity from dedicated out-of-state resources. NCPA and the Project Participants, like other electric utilities, receive administrative allocations of allowances for some of their expected GHG emissions. Entities that emit GHGs at levels above those for which they receive administrative allocations, if any, must purchase the additional allowances they require at the CARB auctions or from other covered entities with surplus allowances. In addition, NCPA and the Project Participants may indirectly bear compliance costs for independent generators that must purchase allowances for their generation.

The Cap-and-Trade program is presently authorized to continue through 2030. Project Participants are expected to receive more than $400 million in proceeds from the sale of these allowances between 2021 and 2030, which will substantially minimize the impact of CARB's requirement to purchase allowance on Project Participants' finances and operations.

GHG Emissions Performance Standard and Financial Commitment Limits. Senate Bill 1368 ("SB 1368") became effective as law on January 1, 2007. SB 1368 provided for an emission performance standard ("EPS") restricting new investments in baseload electric generating resources that exceed a specified rate of GHG emissions (1,100 pounds of carbon dioxide (CO2) per MWh). SB 1368 prohibits POUs from making any "long-term financial commitment" in connection with "baseload generation" that does not satisfy the EPS. Generally, a "long term financial commitment" is any new or renewed power purchase agreement with a term of five years or more, the purchase of an interest in a new power plant or any investment, other than routine maintenance, in an existing power plant that extends the life of the plant by more than five years or results in an increase in its rated capacity. "Baseload generation" means a power plant that is intended to operate at an annualized capacity factor of 60 percent or more.

Energy Procurement and Efficiency Reporting. Senate Bill 1037, chaptered in 2005 ("SB 1037") requires that each POU, including the Project Participants, prior to procuring new energy generation resources, first acquire all available energy efficiency, demand reduction, and renewable resources that are cost-effective, reliable and feasible. SB 1037 also requires each POU to report annually to its customers and to the CEC its investment in energy efficiency and demand reduction programs. The Project Participants are complying with such ongoing reporting requirements.

State law requires that POUs establish, report, and explain the basis of the annual energy efficiency and demand reduction targets once every four years. The Project Participants are complying with such ongoing reporting requirements. The information obtained from the POUs is being used by the CEC to present progress made by the State to double energy efficiency savings in electricity and natural gas final end uses by 2030, to the extent doing so is cost effective, feasible, and does not adversely impact public health and safety, as prescribed in SB 350.

California Renewables Portfolio Standard. California's legislature and executive branch have been active in promoting increasingly stringent renewable energy procurement requirements since 2002. Initial legislative efforts established a renewables portfolio standard ("RPS"), requiring 20% of all renewable electricity retail sales to come from renewable energy generation by 2017. Since then, legislative and executive branch initiatives have raised that standard several times. Senate Bill X1-2, chaptered in 2011 ("SBX 1-2"), required each POU to adopt and implement a renewable energy resource procurement plan and established procurement targets for three compliance periods to be implemented by the procurement plan, culminating in the procurement of eligible renewable energy resources sufficient to provide 33% of retail sales by December 31, 2020. SB 350 established an RPS target of 50% by December 31, 2030 for the amount of electricity generated and sold to retail customers from eligible renewable energy resources for retail sellers and POUs, including interim targets of (i) 40% by the end of the 2021-2024 compliance period, (ii) 45% by the end of the 2025-2027 compliance period and (iii) 50% by the end of the 2028-2030 compliance period. Current law, enacted by Senate Bill 100 ("SB 100"), the 100 Percent Clean Energy Act of 2018, accelerates the State's RPS target established by SB 350 and requires all California utilities to meet a 60% RPS requirement by 2030. SB 100 requires retail electric sellers and POUs 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 (i) 44% of retail sales by December 31, 2024; (ii) 52% of retail sales by December 31, 2027; and (iii) 60% of retail sales by December 1, 2030.

SB 100 additionally establishes a state policy that calls for eligible renewable energy resources and zero-carbon resources to supply 100% of retail sales of electricity to California end-use customers by December 31, 2045. Along with SB 100, Governor Brown signed Executive Order B-55-18 that directs the State to achieve carbon neutrality by 2045 and maintain net negative GHG emissions thereafter. The goal of carbon neutrality by 2045 is in addition to existing statewide targets of reducing GHG emissions. By expanding the State's carbon reduction goal, the State will also look to reduce carbon through sequestration in forests, soils and other natural landscapes.

The governing boards of POUs are responsible for implementing the RPS requirements, rather than the CPUC, as is the case for the IOUs. In addition, the CEC was given certain enforcement authority for POUs and CARB was given the authority to set penalties. The CEC has developed detailed rules to implement its RPS program, and has adopted and, from time to time amended, regulations for the enforcement of the RPS program requirements for POUs.

See "APPENDIX A–SELECTED INFORMATION RELATING TO THE SIGNIFICANT SHARE PROJECT PARTICIPANTS" for information regarding the status of compliance of each of the Significant Share Project Participants with RPS targets under current State law.

Integrated Resource Plans (IRP). SB 350 requires that all POUs with demand greater than 700 gigawatt hours to develop an IRP at least once every five years, no later than January 1, 2019. Four NCPA members are subject to this requirement (Santa Clara, Roseville, Redding, and Palo Alto). Each member completed its IRP within the required timeline. The next IRPs will be due no later than 2024.

Legislation Relating to Wildfires; Related Risks. SB 1028 (chaptered in 2016), required that each POU and each electric cooperative in the State construct, maintain, and operate its electrical lines and equipment in a manner that will minimize the risk of catastrophic wildfire posed by those electrical lines and equipment. SB 1028 required the governing board of each POU to determine, based on historical fire data and local conditions, and in consultation with the fire departments or other entities responsible for the control of wildfires within the geographical area where the utility's overhead electrical lines and equipment are located, whether any portion of that geographical area has a significant risk of wildfire resulting from those electrical lines and equipment, and if so, to present for board approval wildfire mitigation measures the utility intends to undertake to minimize the risk of its overhead electrical lines and equipment causing a catastrophic wildfire.

SB 901 (chaptered in 2018), amended certain provisions of SB 1028 requiring POUs and electric cooperatives to prepare wildfire mitigation measures if the utilities' overhead electrical lines and equipment are located in an area that has a significant risk of wildfire resulting from those electrical lines and equipment. Under SB 901, each POU or electric cooperative is required to have prepared before January 1, 2020 and to prepare annually thereafter, a wildfire mitigation plan. SB 901 requires specified information and elements to be considered as necessary, at minimum, in the wildfire mitigation plan. The POU or electric cooperative is required to present each wildfire mitigation plan in an appropriately noticed public meeting, and to accept comments on its wildfire mitigation plan from the public, other local and state agencies, and interested parties. In addition, SB 901 requires the POU or electric cooperative to contract with a qualified independent evaluator with experience in assessing the safe operation of electrical infrastructure to review and assess the comprehensiveness of its wildfire mitigation plan. The report of the independent evaluator is to be made available to the public and to be presented at a public meeting of the POU's governing board.

AB 1054 was signed into law by Governor Newsom on July 12, 2019. AB 1054 was enacted as an urgency statute to take effect immediately. AB 1054 establishes a Wildfire Fund of approximately $21 billion to provide liquidity for IOUs (only) to facilitate payment of eligible, uninsured third-party damage claims resulting from future catastrophic wildfires. Participation in the Wildfire Fund is exclusive to IOUs. Each of the major IOUs in California are now participating in the in the Wildfire Fund. POUs are not eligible to participate in or receive funding for wildfire claims from the Wildfire Fund.

AB 1054 expands on the existing requirements for POUs established under SB 901 for wildfire mitigation plans. AB 1054 requires each POU, by July 1 of each year, to submit its wildfire mitigation plan to the California Wildfire Safety Advisory Board (the "Wildfire Advisory Board") for review and comment. Under AB 1054, the Wildfire Advisory Board is required to provide comments and an advisory opinion to each POU regarding the content and sufficiency of its plan and to make recommendations on the mitigation of wildfire risks. AB 1054 requires each POU to comprehensively revise its wildfire mitigation plan at least once every three years. NCPA and the Project Participants have submitted their wildfire mitigation plans to the Wildfire Advisory Board as required by AB 1054.

A number of wildfires occurred in California in the last five years. Under the doctrine of inverse condemnation (a legal concept that entitles property owners to just compensation if their property is damaged by a public use), California courts have imposed liability on utilities in legal actions brought by property holders for damages caused by the utility's infrastructure. Thus, if the facilities of a utility, such as its electric distribution and transmission lines, are determined to be the substantial cause of a fire, and the doctrine of inverse condemnation applies, the utility could be liable for damages without having been found negligent. In August 2019, in its decision in the case of *City of Oroville v. Superior Court of Butte County,* No. S243247 (Cal. Aug. 15, 2019) involving damages related to sewage overflows from a city sewer system, the California Supreme Court held that to succeed on an inverse condemnation claim, a property owner must demonstrate that the property damage was the probable result or necessary effect of an inherent risk associated with the design, construction or maintenance of the relevant public improvement. SB 1028, SB 901 or AB 1054 does not address the existing legal doctrine relating to utilities' liability for wildfires. How any future legislation or judicial decisions addresses California's inverse condemnation and liability issues for utilities in the context of wildfires in particular could be significant for the electric utility industry.

NCPA's Commission updated its Wildfire Mitigation Plan, which addresses more than a dozen activities that are intended to reduce the risks of wildfire occurrences related to the operation of its facilities and equipment, as prescribed in SB 901. Measures currently undertaken by NCPA include, among others, a program for the physical inspection of its overhead electrical transmission and distribution lines each year, and routine replacement of poles, towers and insulators as needed, as well as established guidance for the operation of specific facilities during emergency conditions, including wildfires. NCPA owns relatively few miles of overhead electrical transmission and distribution lines and conducts a complete inspection of any line that has tripped out of service prior to re-closing the circuit. In addition, NCPA has developed and implemented a transmission and vegetation management program to provide for the inspection, maintenance, documentation and reporting requirements for vegetation located within or adjacent to NCPA's power line right-of-way in accordance with the standards established by the California Department of Forestry and Fire Protection ("Cal Fire"), state statute and/or the North American Electric Reliability Corporation ("NERC").

NCPA also maintains general liability insurance that would include coverage for wildfires. It should be noted, however, that potential liabilities for utilities in connection with wildfires has adversely impacted the market for insurance, leading to a reduction in underwriting capacity and increased premiums, which effects are expected to continue. For information regarding the wildfire mitigation measures of certain of the Significant Share Project Participants, see also "APPENDIX A – SELECTED INFORMATION RELATING TO THE SIGNIFICANT SHARE PROJECT PARTICIPANTS.

Impact of California Energy Market Developments on NCPA and the Project Participants. The effect of the developments in the California energy markets described above on the Project Participants cannot be fully ascertained at this time. Also, volatility in energy prices in California may return due to a variety of factors that affect both the supply and demand for electric energy in the western United States. These factors include, but are not limited to, the adequacy of generation resources to meet demand at all hours, the availability and cost of renewable energy, the impact of economy-wide GHG emission legislation and regulations, fuel costs and availability, weather effects on customer demand, the impact of climate change, wildfire mitigation and potential liability cost recovery, insurance costs, transmission congestion, the strength of the economy in California and surrounding states and levels of hydroelectric generation within the region (including the Pacific Northwest). This price volatility may contribute to greater volatility in the revenues of the Project Participants' respective electric systems from the sale (and purchase) of electric energy and, therefore, could materially affect each of the Project Participant's financial condition. Each Project Participant undertakes resource planning and risk management activities and manages its resource portfolio to mitigate such price volatility and spot market rate exposure. For a discussion of each of the Significant Share Project Participant's current resource planning activities, see "Power Supply Resources" in each of the Significant Share Project Participants sections in "APPENDIX A–SELECTED INFORMATION RELATING TO THE SIGNIFICANT SHARE PROJECT PARTICIPANTS."

Federal Energy and Environmental Policies and Legislation

Federal Power Act. Although NCPA and its members are exempt from most federal rate regulation pursuant to Section 201(f) of the FPA (see "RATE REGULATION"), the Federal Energy Policy Act of 2005 ("EPAct 2005"), imposed specific exceptions. In particular, FERC was given authority over the behavior of market participants. Under FERC's authority it can impose penalties on any seller for using a manipulative or deceptive device, including market manipulation, in connection with the purchase or sale of energy or of transmission service. The Commodity Futures Trading Commission ("CFTC") also has jurisdiction to enforce certain types of market manipulation or deception claims under the Commodity Exchange Act.

Additionally, pursuant to Section 215 of the FPA, and FERC's implementing regulations and orders, NERC and its regional affiliates, including the Western Electric Coordinating Council ("WECC"), develop and enforce mandatory electric reliability standards to provide for the reliable operation of the bulk electric system. The reliability standards include requirements related to the cybersecurity of systems that could affect the reliable operation of the grid. Those reliability standards, particularly those related to cybersecurity, are continually being amended to address emerging reliability risks.

NCPA and some its members are required to comply with the applicable reliability standards and are potentially subject to penalties if they are found to have violated any of those standards. Violations that pose minimal risk to the bulk electric system may be resolved without any financial penalties, while violations that pose moderate or serious risk may result in significant penalties.

While the penalties for violations of market manipulation rules or reliability standards can be quite serious, these risks can be mitigated by strong compliance programs, and NCPA has taken proactive measures to assure that it has such compliance programs in place.

Regulatory Actions under the Clean Air Act. The United States Environmental Protection Agency (the "EPA") regulates GHG emissions under existing law by imposing monitoring and reporting requirements, and through its permitting programs. Like other air pollutants, GHGs are regulated under the Clean Air Act through the Prevention of Significant Deterioration ("PSD") Permit Program and the Title V Permit Program. A PSD permit is required before commencement of construction of new major stationary sources or major modifications of a major stationary source and requires best available control technologies ("BACT") to control emissions at a facility. Title V permits are operating permits for major sources that consolidate all Clean Air Act requirements (arising, for example, under the Acid Rain, New Source Performance Standards, National Emission Standards for Hazardous Air Pollutants, and/or PSD programs) into a single document and the permit process provides for review of the documents by the EPA, state agencies and the public. GHGs from major natural gas-fired facilities are regulated under both permitting programs through performance standards imposing efficiency and emissions standards.

The focus of federal action toward the regulation of GHG emissions has changed significantly in recent years. In October 2015, under the Obama Administration, the EPA published the Clean Power Plan, which would have established carbon pollution standards for new, modified, and reconstructed power plans, and carbon pollution emission guidelines for existing electricity utility generating units. The total national emissions reduction goal under the Clean Power Plan called for a 32 percent reduction in GHG emissions from 2005 levels by 2030, with incremental interim goals for the years from 2022 through 2029. The program would have allowed states multiple options for measuring reductions and established different reduction goals depending upon the regulatory program set forth in the state plan.

A combination of legal challenges and a change in the federal administration led to the repeal of the Clean Power Plan, replaced by the Affordable Clean Energy rule in July 2019. On January 19, 2021, upon a challenge by a number of environmental advocates, state and municipal attorneys, and others, the D.C. Circuit vacated the Affordable Clean Energy Rule. NCPA and the Project Participants are unable to predict the timing or content of any new regulations that may be proposed to replace the Affordable Clean Energy Rule.

Changing Laws and Requirements Generally

Electric utilities are subject to continuing environmental regulation. Federal, State and local standards and procedures which regulate the environmental impact of electric utilities are subject to change. These changes may arise from continuing legislative, regulatory and judicial action regarding such standards and procedures. Consequently, there is no assurance that any facilities or projects of

NCPA or a Project Participant will remain subject to the laws and regulations currently in effect, will always be in compliance with future laws and regulations or will always be able to obtain all required operating permits. An inability to comply with environmental standards could result in, for example, additional capital expenditures, reduced operating levels or the shutdown of individual units not in compliance. In addition, increased environmental laws and regulations may create certain barriers to new facility development, may require modification of existing facilities and may result in additional costs for affected resources.

In addition, on both the State and federal levels, legislation is introduced frequently addressing domestic energy policies and various environmental matters and impacts relating to energy, including the generation of energy using conventional and unconventional technologies. Issues raised in recent legislative proposals have included implementation of energy efficiency and renewable energy standards, addressing transmission planning, siting and cost allocation to support the construction of renewable energy facilities, cybersecurity legislation that would allow FERC to issue interim measures to protect critical electric infrastructure, a federal cap-and-trade program to reduce GHG emissions, and renewable energy incentives that could provide grants and credits to municipal utilities to invest in renewable energy infrastructure. Congress has also considered other bills relating to energy supplies and development (such as expedited permitting for natural gas drilling projects, reducing regulatory burdens, and climate change and water quality).

Also, over the course of the last two and a half years, the U.S. hydropower industry, represented by the National Hydropower Association ("NHA"), has been actively engaged in discussions with environmental and recreational stakeholders to as part of a Stanford University-initiated *Uncommon Dialogue* effort. The objective is to identify areas of common agreement related to public policy that furthers the clean energy attributes of hydropower as part of the global climate change solution, while simultaneously assuring the preservation of our nation's rivers. It is hoped that this dialogue will, in part, lead to Congressional action on regulatory streamlining and other incentives for our nation's hydropower industry. NCPA is an engaged participant in NHA and has worked to help facilitate agreement and consensus in these areas.

Neither NCPA nor any Project Participant is able to predict at this time whether any of these or other legislative proposals will be enacted into law and, if so, the impact they may have on the operations and finances of such entities or on the electric utility industry in general.

CAISO Markets

General. Any electricity sales or purchases NCPA makes in the wholesale energy markets operated by the CAISO are subject to the CAISO tariff, which is a FERC-jurisdictional tariff. CAISO's tariff includes rules governing how sellers may bid electricity (*i.e.*, offer for sale) into the energy markets and rules governing market power mitigation of sellers. CAISO regularly proposes changes to its tariff, subject to FERC approval. Additionally, FERC can, and does, order changes to CAISO's tariff if FERC (on its own initiative or prompted by a complaint) determines that CAISO's tariff is unjust, unreasonable, or unduly discriminatory. Such regulatory changes can impact prices for transmission, electricity and capacity.

CAISO Market Initiatives. The CAISO markets are subject to continued change in response to FERC orders, the increased integration of intermittent renewable resources, changing environmental constraints, the ongoing efforts to combat market manipulation and evolving reliability requirements. CAISO Tariff changes related to these and other issues are currently under discussion in CAISO stakeholder processes and in ongoing FERC proceedings. In most cases, these proposals are not sufficiently final in order to determine their likely impact on NCPA or the Project Participants. However, the following issues and proposed CAISO operational and market changes may have significant impacts on NCPA and the Project Participants, as well as California and Western electric utilities generally. NCPA will continue to monitor the various initiatives proposed by the CAISO and participate in its stakeholder processes to ensure that its interests are protected.

Resource Adequacy Requirements. Resource Adequacy requirements apply to NCPA and its members, including the Project Participants, to ensure that market participants have contracted for sufficient amounts of the right types of capacity to be available in the markets. To the extent that a load serving entity ("LSE") fails to procure sufficient capacity resources to meet its loads, it is subject to payment of CAISO procurement costs of replacement capacity. To the extent that a shortfall cannot be attributed to a specific LSE, the costs will be spread as part of market uplift charges. These risks apply in the same manner to all LSEs. Due to the increased integration of renewables, discussed above, the CAISO is contemplating what could be significant changes to the Resource Adequacy framework, with the potential for impacts on market participant costs. It is still too early to assess the potential impacts on NCPA. The CPUC has ongoing dockets that could also result in changes to the Resource Adequacy and CAISO's markets. However, the details of such changes remain to be established.

Transmission Access Charge Review. The CAISO undertook a review of its Transmission Access Charge, with a view to potentially changing the methodology used for allocating transmission costs. Although the current proposal should not adversely impact NCPA or its members, any change of this nature raises concerns and NCPA is unable to predict the outcome of the tariff revisions process at FERC.

Extension of Day Ahead Markets to Energy Imbalance Market. The CAISO began financially binding operation of the western Energy Imbalance Market ("EIM") in 2014. An EIM is a voluntary market that provides a sub-hourly economic dispatch of participating resources for balancing supply and demand every five minutes. CAISO has announced its intention to extend the CAISO's day ahead market into the EIM, rather than leaving it as only a real time market. While these proposals have not yet been developed, much less analyzed, such a change has the impact to affect prices paid in the CAISO markets, and to impact electric utilities inside and outside of California.

Redesigned Day-Ahead Markets. As the fleet of supply resources within the CAISO balancing authority area evolves to reflect a greater proportion of intermittent renewable resources, there is the concomitant increase in uncertainty between the CAISO's day-ahead and real-time markets for the efficient commitment of resources required to respond to increased CAISO net load variability. The CAISO has undertaken an initiative to redesign its day-ahead market structure that will provide for the co-optimized commitment of both upward and downward reserve capacity in the day-ahead timeline so that sufficient capacity will be available for real-time dispatch. Such changes could impact electric utilities in California. While the details of the CAISO's redesigned day-ahead market structure have not yet been finalized, the CAISO indicates that its redesigned day-ahead market structure is intended to complement and be deployed in unison with changes emanating from the CAISO's Resource Adequacy initiative and extension of EIM.

Cybersecurity

NCPA and the Project Participants rely on computers and technology in the conduct of their operations. NCPA and the Project Participants face cyber threats from time to time including, but not limited to, hacking, viruses, malware and other forms of attacks on their computing and other digital networks and systems. Cybersecurity incidents could result from unintentional events, or from deliberate attacks by unauthorized entities or individuals attempting to gain access to NCPA's or a Project Participant's technology for the purposes of misappropriating assets or information or causing operational disruption and damage, including with respect to NCPA's or a Project Participant's electric system assets.

United States government agencies have in the past issued warnings indicating that critical infrastructure sectors such as electric systems may be specific targets of cybersecurity threats. Attacks directed at critical electric sector operations could damage distribution, transmission and/or generation assets, cause operational malfunctions and outages, and result in costly recovery and remediation efforts. Cyberattacks are becoming more sophisticated and certain cyber incidents, such as surveillance, may remain undetected for an extended period. NERC, as the electric reliability organization, has developed critical infrastructure protection cybersecurity reliability standards that are applicable to NCPA and the electric systems of the Project Participants. Accordingly, NCPA and the Project Participants have a variety of security measures and safeguards in place. However, no assurances can be given that any existing or additional safety and security measures will prove adequate in the event that cyberattacks or military conflicts or terrorist activities, including cyber terrorism, are directed against NCPA's or a Project Participant's systems technology or electric system assets.

COVID-19

The spread of the novel strain of coronavirus (and variants thereof) and the disease it causes (now known as "COVID-19") has had significant negative impacts throughout the world, including in California. In 2020, the World Health Organization declared the COVID-19 outbreak to be a pandemic, and states of emergency have been declared by the United States, the State and numerous counties throughout the State. The purpose behind these declarations was to coordinate and formalize emergency actions across federal, state and local governmental agencies, and to proactively prepare for a wider spread of the virus.

On March 19, 2020, in an effort to slow the spread of COVID-19, Governor Newsom issued Executive Order N-33-20 ordering individuals living in the State to stay home or at their place of residence except for specified exceptions, including exceptions for certain sectors of the workforce that were classified as providing essential services and products, which allowed businesses and workers in such sectors to continue to operate on-site operations while Executive Order N-33-20 was effective. On June 11, 2021, Governor Newsom issued two executive orders, which became effective on June 15, 2021, which had the effect of rescinding a majority of the COVID-19-related restrictions and providing a timeline for gradually lifting certain of the other restrictions that were not fully rescinded on June 15, 2021. On December 13, 2021, and as further extended through February 15, 2022, California Health and Human Services Agency Secretary Dr. Mark Ghaly reinstated a statewide indoor mask mandate in response to the spread of the Omicron variant.

With widespread vaccination in the United States and many countries worldwide, governmental-imposed stay-at-home orders and restrictions on operations of schools and businesses implemented to respond to and control the outbreak have been eased or eliminated. However, new variants of the disease continue to emerge and restrictions may be re-imposed in various jurisdictions from time to time as local conditions warrant, such as the temporary statewide indoor mask mandates. NCPA cannot predict whether any reinstatement or expansion of stay-at-home orders and travel or other restrictions will occur or when a full resumption of all economic activity will be achieved.

Electric utility services are in a federally designated critical infrastructure sector with exemptions under the California Governor's State-wide stay-at-home order and the local orders, as needed to maintain continuity of operations. In response to changing requirements, NCPA has implemented a variety of measures with respect to essential workers, telecommuting options, return to work protocols and back-up operations designed to maintain its business functions and to protect public health and the health and safety of its employees. NCPA's ability to conduct its operations has not been impaired.

The ultimate impact of COVID-19 on the operations and finances of NCPA and the Project Participants is unknown and there can be no assurances that COVID-19 will not materially adversely impact the financial condition of NCPA or the Project Participants in the future. There are many variables that will continue to contribute to the economic impact of the COVID-19 pandemic and the recovery therefrom, including the length of time social distancing measures are in place, the effectiveness of State and federal government relief programs and the timing for containment and treatment, new coronavirus strains, vaccinations efforts and vaccine hesitancy. NCPA cannot predict the extent or duration of such impacts.

See "APPENDIX A–SELECTED INFORMATION RELATING TO THE SIGNIFICANT SHARE PROJECT PARTICIPANTS" hereto for information regarding the current and potential impact of the COVID-19 outbreak on the operations and finances of the electric systems of the Significant Share Project Participants.

Other Factors

The electric utility industry in general has been, or in the future may be, affected by a number of other factors which could impact the financial condition and competitiveness of many electric utilities and the level of utilization of generating and transmission facilities. In addition to the factors that are discussed above, such factors include, among others: (a) effects of compliance with rapidly changing environmental, safety, licensing, regulatory and legislative requirements other than those described above (including those affecting nuclear power plants or potential new energy storage requirements); (b) changes resulting from conservation and demand-side management programs on the timing and use of electric energy; (c) effects on the integration and reliability of power supply from the increased usage of renewables; (d) changes resulting from a national energy policy; (e) effects of competition from other electric utilities (including increased competition resulting from a movement to allow direct access or from mergers, acquisitions and "strategic alliances" of competing electric and natural gas utilities and from competitors transmitting less expensive electricity from much greater distances over an interconnected system) and new methods of, and new facilities for, producing low-cost electricity; (f) the repeal of certain federal statutes that would have the effect of increasing the competitiveness of many investor-owned utilities; (g) increased competition from independent power producers and marketers, brokers and federal power marketing agencies; (h) "self-generation" or "distributed generation" (such as microturbines, fuel cells and solar installations) by industrial and commercial customers and others; (i) issues relating to the ability to issue tax-exempt obligations, including severe restrictions on the ability to sell to nongovernmental entities electricity from generation projects and transmission service from transmission line projects financed with outstanding tax-exempt obligations; (j) effects of inflation on the operating and maintenance costs of an electric utility and its facilities; (k) changes from projected future load requirements; (l) increases in costs and uncertain availability of capital; (m) shifts in the availability and relative costs of different fuels (including the cost of natural gas and nuclear fuel); (n) sudden and dramatic increases in the price of energy purchased on the open market that may occur in times of high peak demand in an area of the country experiencing such high peak demand, such as has occurred in the past in California; (o) inadequate risk management procedures and practices with respect to, among other things, the purchase and sale of energy and transmission capacity; (p) other legislative changes, voter initiatives, referenda and statewide propositions; (q) effects of the changes in the economy, population and demand of customers within a utility's service area; (r) effects of possible manipulation of the electric markets; (s) acts of terrorism or cyber-terrorism; (t) natural disasters or other physical calamities, including, but not limited to, earthquakes, floods and wildfires, and potential liabilities of electric utilities in connection therewith; (u) changes to the climate; and (v) adverse impacts to the market for insurance relating to recent wildfires and other calamities, leading to higher costs or prohibitively expensive coverage, or limited or unavailability of coverage for certain types of risk. Any of these factors (as well as other factors) could have an adverse effect on the financial condition of any given electric utility and likely will affect individual utilities in different ways.

LITIGATION

There is no controversy or litigation of any nature now pending or threatened restraining or enjoining the issuance, sale, execution or delivery of the 2022 Bonds, or in any way contesting or affecting the validity of the 2022 Bonds or any proceedings of NCPA taken with respect to the issuance or sale thereof.

Upon the basis of information presently available, NCPA and its General Counsel believe that there is no litigation pending or threatened against NCPA which will materially adversely affect the Project or the respective sources of payment for the 2022 Bonds.

California Energy Market Dysfunction, Refund Dispute and Related Litigation

Following the 1998 operation of the CAISO and the California Power Exchange (the "PX"), the deregulated electricity and natural gas markets in California became increasingly dysfunctional, with very high prices in 2000-2001, resulting in the eventual bankruptcy of the PX, PG&E (and others) and a number of orders from FERC. The IOUs (PG&E, Southern California Edison Company ("Edison") and San Diego Gas & Electric Company ("SDG&E")) and the State of California and the CPUC have been pursuing claims for refunds against all sellers into the market, including NCPA and other power-producing municipally owned utilities.

Those claims for refunds against varying groups of sellers have been pursued in a number of *fora* since early Fall, 2000, and have been through numerous FERC proceedings, State and Federal court decisions, and the U.S. Supreme Court. Some of those claims are still being pursued both at FERC and in the Courts of Appeal. While NCPA considered the claims against it to be lacking in legal merit, NCPA entered into a settlement with the plaintiffs which provides the terms of a final resolution of all of these claims and of the bankruptcy claims held by NCPA against PG&E and the PX. The settlement agreement was approved by FERC on April 29, 2010. That approval by FERC was the last regulatory step necessary to resolve these disputes between those parties in their entirety, as well as a separate lawsuit filed by the State of California. The state court proceeding against NCPA was dismissed with prejudice on May 20, 2010.

The proceedings at FERC and in the Court of Appeals remain ongoing, but the remaining parties to those proceedings have not asserted any claims against NCPA. NCPA continues to monitor the proceedings to protect its interests.

FERC and CAISO Proceedings: Market Redesign

Most of the matters being contested at FERC or being discussed in CAISO stakeholder processes involving NCPA or the Project Participants concern the current operation or potential changes to the CAISO market. For a discussion of potential changes in the CAISO market, see "CERTAIN FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY – CAISO Markets."

Other Proceedings

NCPA is involved in various other state court proceedings incidental to its operations. Based on its review of those proceedings with its General Counsel, NCPA believes that the ultimate aggregate liability, if any, resulting from those proceedings will not have a material adverse effect on its financial position.

TAX MATTERS

2022 Series A Bonds

Federal Income Taxes. The Internal Revenue Code of 1986, as amended (the "Code"), imposes certain requirements that must be met subsequent to the issuance and delivery of the 2022 Series A Bonds for interest thereon to be and remain excluded from gross income for federal income tax purposes. Noncompliance with such requirements could cause the interest on the 2022 Series A Bonds to be included in gross income for federal income tax purposes retroactive to the date of issue of the 2022 Series A Bonds. Pursuant to the Indenture and the Tax and Nonarbitrage Certificate executed by NCPA in connection with the issuance of the 2022 Series A Bonds (the "Tax Certificate"), NCPA has covenanted not to take any action, or fail to take any action, if any such action or failure to take action would adversely affect the exclusion from gross income of the interest on the 2022 Series A Bonds under Section 103 of the Code. In addition, NCPA has made certain representations and certifications in the Indenture and Tax Certificate. Special Tax Counsel will not independently verify the accuracy of those representations and certifications.

In the opinion of Nixon Peabody LLP, Special Tax Counsel, under existing law and assuming compliance with the aforementioned covenant, and the accuracy of certain representations and certifications made by NCPA described above, interest on the 2022 Series A Bonds is excluded from gross income for federal income tax purposes under Section 103 of the Code. Special Tax Counsel is also of the opinion that such interest is not treated as a preference item in calculating the alternative minimum tax imposed under the Code.

State Taxes. Special Tax Counsel is also of the opinion that interest on the 2022 Series A Bonds is exempt from personal income taxes of the State of California under present State law. Special Tax Counsel expresses no opinion as to other state or local tax consequences arising with respect to the 2022 Series A Bonds nor as to the taxability of the 2022 Series A Bonds or the income therefrom under the laws of any state other than California.

Original Issue Premium. 2022 Series A Bonds sold at prices in excess of their principal amount will have amortizable bond premium which is not deductible from gross income for federal income tax purposes. The amount of amortizable bond premium for a taxable year is determined actuarially on a constant interest rate basis over the term of each Premium Bond based on the purchaser's yield to maturity (or, in the case of Premium Bonds callable prior to their maturity, over the period to the call date, based on the purchaser's yield to the call date and giving effect to any call premium). For purposes of determining gain or loss on the sale or other disposition of a Premium Bond, an initial purchaser who acquires such obligation with an amortizable bond premium is required to decrease such purchaser's adjusted basis in such Premium Bond annually by the amount of amortizable bond premium for the taxable year. The amortization of bond premium may be taken into account as a reduction in the amount of tax-exempt income for purposes of determining various other tax consequences of owning such Premium Bonds. Owners of the Premium Bonds are advised that they should consult with their own advisors with respect to the state and local tax consequences of owning such Premium Bonds.

Ancillary Tax Matters. Ownership of the 2022 Series A Bonds may result in other federal tax consequences to certain taxpayers, including, without limitation, certain S corporations, foreign corporations with branches in the United States, property and casualty insurance companies, individuals receiving Social Security or Railroad Retirement benefits, and individuals seeking to claim the earned income credit, and taxpayers (including banks, thrift institutions, and other financial institutions) who may be deemed to have incurred or continued indebtedness to purchase or to carry the 2022 Series A Bonds. Prospective investors are advised to consult their own tax advisors regarding these rules.

Interest paid on tax-exempt obligations such as the 2022 Series A Bonds is subject to information reporting to the Internal Revenue Service ("IRS") in a manner similar to interest paid on taxable obligations. In addition, interest on the 2022 Series A Bonds may be subject to backup withholding if such interest is paid to a registered owner that (a) fails to provide certain identifying information (such as the registered owner's taxpayer identification number) in the manner required by the IRS, or (b) has been identified by the IRS as being subject to backup withholding.

Special Tax Counsel are not rendering any opinions as to any federal tax matters other than those described in the their opinion attached in Appendix F. Prospective investors, particularly those who may be subject to special rules described above, are advised to consult their own tax advisors regarding the federal tax consequences of owning and disposing of the 2022 Series A Bonds, as well as any tax consequences arising under the laws of any state or other taxing jurisdiction.

Changes in Law and Post Issuance Events. Legislative or administrative actions and court decisions, at either the federal or state level, could have an adverse impact on the potential benefits of the exclusion from gross income of the interest on the 2022 Series A Bonds for federal or state income tax purposes, and thus on the value or marketability of the 2022 Series A Bonds. This could result from changes to federal or state income tax rates, changes in the structure of federal or state income taxes (including replacement with another type of tax), repeal of the exclusion of the interest on the 2022 Series A Bonds from gross income for federal or state income tax purposes, or otherwise. It is not possible to predict whether any legislative or administrative actions or court decisions having an adverse impact on the federal or state income tax treatment of holders of the 2022 Series A Bonds may occur. Prospective purchasers of the 2022 Series A Bonds should consult their own tax advisors regarding the impact of any change in law on the 2022 Series A Bonds.

Special Tax Counsel has not undertaken to advise in the future whether any events after the date of issuance and delivery of the 2022 Series A Bonds may affect the tax status of interest on the 2022 Series A Bonds. Special Tax Counsel expresses no opinion as to any federal, state or local tax law consequences with respect to the 2022 Series A Bonds, or the interest thereon, if any action is taken with respect to the 2022 Series A Bonds or the proceeds thereof upon the advice or approval of other counsel.

2022 Series B Bonds

The following is a summary of certain anticipated United States federal income tax consequences of the purchase, ownership and disposition of the 2022 Series B Bonds. The summary is based upon the provisions of the Code, the Treasury Regulations promulgated thereunder and the judicial and administrative rulings and decisions now in effect, all of which are subject to change. Such authorities may be repealed, revoked, or modified, possibly with retroactive effect, so as to result in United States federal income tax consequences different from those described below. The summary generally addresses 2022 Series B Bonds held as capital assets within the meaning of Section 1221 of the Code and does not purport to address all aspects of federal income taxation that may affect particular investors in light of their individual circumstances or certain types of investors subject to special treatment under the federal income tax laws, including but not limited to financial institutions, insurance companies, dealers in securities or currencies, persons holding such 2022 Series B Bonds as a hedge against currency risks or as a position in a "straddle," "hedge," "constructive sale transaction" or "conversion transaction" for tax purposes, or persons whose functional currency is not the United States dollar. It also does not deal with holders other than original purchasers that acquire 2022 Series B Bonds at their initial issue price except where otherwise specifically noted. Potential purchasers of the 2022 Series B Bonds should consult their own tax advisors in determining the federal, state, local, foreign and other tax consequences to them of the purchase, holding and disposition of the 2022 Series B Bonds.

NCPA has not sought and will not seek any rulings from the Internal Revenue Service with respect to any matter discussed herein. No assurance can be given that the Internal Revenue Service would not assert, or that a court would not sustain, a position contrary to any of the tax characterizations and tax consequences set forth below.

U.S. Holders. As used herein, the term ‘‘U.S. Holder’’ means a beneficial owner of 2022 Series B Bonds that is (a) an individual citizen or resident of the United States for federal income tax purposes, (b) a corporation, including an entity treated as a corporation for federal income tax purposes, created or organized in or under the laws of the United States or any State thereof (including the District of Columbia), (c) n estate whose income is subject to federal income taxation regardless of its source, or (d) trust if a court within the United States can exercise primary supervision over the administration of the trust and one or more U.S. persons have the authority to control all substantial decisions of the trust. Notwithstanding clause (d) of the preceding sentence, to the extent provided in Treasury regulations, certain trusts in existence on August 20, 1996, and treated as United States persons prior to that date that elect to continue to be treated as United States persons also will be U.S. Holders. In addition, if a partnership (or other entity or arrangement treated as a partnership for federal income tax purposes) holds 2022 Series B Bonds, the tax treatment of a partner in the partnership generally will depend upon the status of the partner and the activities of the partnership. If a U.S. Holder is a partner in a partnership (or other entity or arrangement treated as a partnership for federal income tax purposes) that holds 2022 Series B Bonds, the U.S. Holder is urged to consult its own tax advisor regarding the specific tax consequences of the purchase, ownership and dispositions of the 2022 Series B Bonds.

Taxation of Interest Generally. Interest on the 2022 Series B Bonds is not excluded from gross income for federal income tax purposes under Code Section 103 and so will be fully subject to federal income taxation. Purchasers (other than those who purchase 2022 Series B Bonds in the initial offering at their principal amounts) will be subject to federal income tax accounting rules affecting the timing and/or characterization of payments received with respect to such 2022 Series B Bonds. In general, interest paid on the 2022 Series B Bonds and recovery of any accrued original issue discount and market discount will be treated as ordinary income to a Bondholder, and after adjustment for the foregoing, principal payments will be treated as a return of capital to the extent of the U.S. Holder’s adjusted tax basis in the 2022 Series B Bonds and capital gain to the extent of any excess received over such basis.

Original Issue Discount. The following summary is a general discussion of certain federal income tax consequences of the purchase, ownership and disposition of 2022 Series B Bonds issued with original issue discount (“Discount 2022 Series B Bonds”). A 2022 Series B Bond will be treated as having been issued at an original issue discount if the excess of its “stated redemption price at maturity” (defined below) over its issue price (defined as the initial offering price to the public at which a substantial amount of the 2022 Series B Bonds of the same maturity have first been sold to the public, excluding bond houses and brokers) equals or exceeds one quarter of one percent of such 2022 Series B Bond’s stated redemption price at maturity multiplied by the number of complete years to its maturity (or, in the case of an installment obligation, its weighted average maturity).

A 2022 Series B Bond’s “stated redemption price at maturity” is the total of all payments provided by the 2022 Series B Bond that are not payments of “qualified stated interest.” Generally, the term “qualified stated interest” includes stated interest that is unconditionally payable in cash or property (other than debt instruments of the issuer) at least annually at a single fixed rate or certain floating rates.

In general, the amount of original issue discount includible in income by the initial holder of a Discount Bond is the sum of the "daily portions" of original issue discount with respect to such 2022 Series B Bond for each day during the taxable year in which such holder held such 2022 Series B Bond. The daily portion of original issue discount on any Discount Bond is determined by allocating to each day in any "accrual period" a ratable portion of the original issue discount allocable to that accrual period.

An accrual period may be of any length, and may vary in length over the term of a 2022 Series B Bond, provided that each accrual period is not longer than one year and each scheduled payment of principal or interest occurs at the end of an accrual period. The amount of original issue discount allocable to each accrual period is equal to the difference between (i) the product of the 2022 Series B Bond's adjusted issue price at the beginning of such accrual period and its yield to maturity (determined on the basis of compounding at the close of each accrual period and appropriately adjusted to take into account the length of the particular accrual period) and (ii) the amount of any qualified stated interest payments allocable to such accrual period. The "adjusted issue price" of a Discount Bond at the beginning of any accrual period is the sum of the issue price of the Discount Bond plus the amount of original issue discount allocable to all prior accrual periods minus the amount of any prior payments on the 2022 Series B Bond that were not qualified stated interest payments. Under these rules, holders generally will have to include in income increasingly greater amounts of original issue discount in successive accrual periods.

Holders utilizing the accrual method of accounting may generally, upon election, include in gross income all interest (including stated interest, acquisition discount, original issue discount, de minimis original issue discount, market discount, de minimis market discount, and unstated interest, as adjusted by any amortizable bond premium or acquisition premium) on the 2022 Series B Bond by using the constant yield method applicable to original issue discount, subject to certain limitations and exceptions.

Market Discount. Any owner who purchases a 2022 Series B Bond at a price which includes market discount (*i.e.*, at a purchase price that is less than its adjusted issue price in the hands of an original owner) in excess of a prescribed de minimis amount will be required to recharacterize all or a portion of the gain as ordinary income upon receipt of each scheduled or unscheduled principal payment or upon other disposition. In particular, such owner will generally be required either (a) to allocate each such principal payment to accrued market discount not previously included in income and to recognize ordinary income to that extent and to treat any gain upon sale or other disposition of such a 2022 Series B Bond as ordinary income to the extent of any remaining accrued market discount or (b) to elect to include such market discount in income currently as it accrues on all market discount instruments acquired by such owner on or after the first day of the taxable year to which such election applies.

The Code authorizes the Treasury Department to issue regulations providing for the method for accruing market discount on debt instruments the principal of which is payable in more than one installment. Until such time as regulations are issued by the Treasury Department, certain rules described in the legislative history of the Tax Reform Act of 1986 will apply. Under those rules, market discount will be included in income either (a) on a constant interest basis or (b) in proportion to the accrual of stated interest.

An owner of a 2022 Series B Bond who acquires such 2022 Series B Bond at a market discount also may be required to defer, until the maturity date of such 2022 Series B Bonds or the earlier disposition in a taxable transaction, the deduction of a portion of the amount of interest that the owner paid or accrued during the taxable year on indebtedness incurred or maintained to purchase or carry a 2022 Series B Bond in excess of the aggregate amount of interest (including original issue discount) includable in such owner's gross income for the taxable year with respect to such 2022 Series B Bond. The amount of such net interest expense deferred in a taxable year may not exceed the amount of market discount accrued on the 2022 Series B Bond for the days during the taxable year on which the owner held the 2022 Series B Bond and, in general, would be deductible when such market discount is includable in income. The amount of any remaining deferred deduction is to be taken into account in the taxable year in which the 2022 Series B Bond matures or is disposed of in a taxable transaction. In the case of a disposition in which gain or loss is not recognized in whole or in part, any remaining deferred deduction will be allowed to the extent gain is recognized on the disposition. This deferral rule does not apply if the Bondholder elects to include such market discount in income currently as described above.

Bond Premium. A holder of a 2022 Series B Bond who purchases such 2022 Series B Bond at a cost greater than its remaining redemption amount will have amortizable bond premium. If the holder elects to amortize this premium under Section 171 of the Code (which election will apply to all taxable bonds held by the holder on the first day of the taxable year to which the election applies and to all taxable bonds thereafter acquired by the holder), such a holder must amortize the premium using constant yield principles based on the holder's yield to maturity. Amortizable bond premium is generally treated as an offset to interest income, and a reduction in basis is required for amortizable bond premium that is applied to reduce interest payments. Holders of any 2022 Series B Bonds who acquire such 2022 Series B Bonds at a premium should consult with their own tax advisors with respect to state and local tax consequences of owning such 2022 Series B Bonds.

Surtax on Unearned Income. Recently enacted legislation generally imposes a tax of 3.8% on the "net investment income" of certain individuals, trusts and estates for taxable years beginning after December 31, 2012. Among other items, net investment income generally includes gross income from interest and net gain attributable to the disposition of certain property, less certain deductions. U.S. Holders should consult their own tax advisors regarding the possible implications of this legislation in their particular circumstances.

Sale or Redemption of 2022 Series B Bonds. A Bondholder's adjusted tax basis for a 2022 Series B Bond is the price such owner pays for the 2022 Series B Bond plus the amount of original issue discount and market discount previously included in income and reduced on account of any payments received on such 2022 Series B Bond other than "qualified stated interest" and any amortized bond premium. Gain or loss recognized on a sale, exchange or redemption of a 2022 Series B Bond, measured by the difference between the amount realized and the Bondholder's tax basis as so adjusted, will generally give rise to capital gain or loss if the 2022 Series B Bond is held as a capital asset (except in the case of 2022 Series B Bonds acquired at a market discount, in which case a portion of the gain will be characterized as interest and therefore ordinary income).

If the terms of the 2022 Series B Bonds are materially modified, in certain circumstances, a new debt obligation would be deemed created and exchanged for the prior obligation in a taxable transaction. Among the modifications which may be treated as material are those which related to the redemption provisions and, in the case of a nonrecourse obligation, those which involve the substitution of collateral. The defeasance of the 2022 Series B Bonds may also result in a deemed sale or exchange of such 2022 Series B Bonds under certain circumstances.

EACH POTENTIAL HOLDER OF 2022 SERIES B BONDS SHOULD CONSULT ITS OWN TAX ADVISOR CONCERNING (1) THE TREATMENT OF GAIN OR LOSS ON SALE OR REDEMPTION OF THE 2022 SERIES B BONDS, AND (2) THE CIRCUMSTANCES IN WHICH 2022 SERIES B BONDS WOULD BE DEEMED REISSUED AND THE LIKELY EFFECTS, IF ANY, OF SUCH REISSUANCE.

Non-U.S. Holders. The following is a general discussion of certain United States federal income tax consequences resulting from the beneficial ownership of 2022 Series B Bonds by a person other than a U.S. Holder, a former United States citizen or resident, or a partnership or entity treated as a partnership for United States federal income tax purposes (a "Non-U.S. Holder").

Subject to the discussion of backup withholding and the Foreign Account Tax Compliance Act ("FATCA"), payments of principal by NCPA or any of its agents (acting in its capacity as agent) to any Non-U.S. Holder will not be subject to federal withholding tax. In the case of payments of interest to any Non-U.S. Holder, however, federal withholding tax will apply unless the Non-U.S. Holder (1) does not own (actually or constructively) 10-percent or more of the voting equity interests of NCPA, (2) is not a controlled foreign corporation for United States tax purposes that is related to NCPA (directly or indirectly) through stock ownership, and (3) is not a bank receiving interest in the manner described in Section 881(c)(3)(A) of the Code. In addition, either (1) the Non-U.S. Holder must certify on the applicable IRS Form W-8 (series) (or successor form) to NCPA, its agents or paying agents or a broker under penalties of perjury that it is not a U.S. person and must provide its name and address, or (2) a securities clearing organization, bank or other financial institution, that holds customers' securities in the ordinary course of its trade or business and that also holds the 2022 Series B Bonds must certify to NCPA or its agent under penalties of perjury that such statement on the applicable IRS Form W-8 (series) (or successor form) has been received from the Non-U.S. Holder by it or by another financial institution and must furnish the interest payor with a copy.

Interest payments may also be exempt from federal withholding tax depending on the terms of an existing Federal Income Tax Treaty, if any, in force between the U.S. and the resident country of the Non-U.S. Holder. The U.S. has entered into an income tax treaty with a limited number of countries. In addition, the terms of each treaty differ in their treatment of interest and original issue discount payments. Non-U.S. Holders are urged to consult their own tax advisor regarding the specific tax consequences of the receipt of interest payments, including original issue discount. A Non-U.S. Holder that does not qualify for exemption from withholding as described above must provide NCPA or its agent with documentation as to his, her, or its identity to avoid the U.S. backup withholding tax on the amount allocable to a Non-U.S. Holder. The documentation may require that the Non-U.S. Holder provide a U.S. tax identification number.

If a Non-U.S. Holder is engaged in a trade or business in the United States and interest on a 2022 Series B Bond held by such holder is effectively connected with the conduct of such trade or business, the Non-U.S. Holder, although exempt from the withholding tax discussed above (provided that such holder timely furnishes the required certification to claim such exemption), may be subject to United States federal income tax on such interest in the same manner as if it were a U.S. Holder. In addition, if the Non-U.S. Holder is a foreign corporation, it may be subject to a branch profits tax equal to 30% (subject to a reduced rate under an applicable treaty) of its effectively connected earnings and profits for the taxable year, subject to certain adjustments. For purposes of the branch profits tax, interest on a 2022 Series B Bond will be included in the earnings and profits of the holder if the interest is effectively connected with the conduct by the holder of a trade or business in the United States. Such a holder must provide the payor with a properly executed IRS Form W-8ECI (or successor form) to claim an exemption from United States federal withholding tax.

Generally, any capital gain realized on the sale, exchange, retirement or other disposition of a 2022 Series B Bond by a Non-U.S. Holder will not be subject to United States federal income or withholding taxes if (1) the gain is not effectively connected with a United States trade or business of the Non-U.S. Holder, and (2) in the case of an individual, the Non-U.S. Holder is not present in the United States for 183 days or more in the taxable year of the sale, exchange, retirement or other disposition, and certain other conditions are met.

For newly issued or reissued obligations, such as the 2022 Series B Bonds, FATCA imposes U.S. withholding tax on interest payments and, for dispositions after December 31, 2018, gross proceeds of the sale of the 2022 Series B Bonds paid to certain foreign financial institutions (which is broadly defined for this purpose to generally include non-U.S. investment funds) and certain other non-U.S. entities if certain disclosure and due diligence requirements related to U.S. accounts or ownership are not satisfied, unless an exemption applies. An intergovernmental agreement between the United States and an applicable non-U.S. country may modify these requirements. In any event, Bondholders or beneficial owners of the 2022 Series B Bonds shall have no recourse against NCPA, nor will NCPA be obligated to pay any additional amounts to "gross up" payments to such persons, as a result of any withholding or deduction for, or on account of, any present or future taxes, duties, assessments or government charges with respect to payments in respect of the 2022 Series B Bonds. However, it should be noted that on December 13, 2018, the IRS issued Proposed Treasury Regulation Section 1.1473-1(a)(1) which proposes to remove gross proceeds from the definition of "withholdable payment" for this purpose.

Non-U.S. Holders should consult their own tax advisors with respect to the possible applicability of federal withholding and other taxes upon income realized in respect of the 2022 Series B Bonds.

Information Reporting and Backup Withholding. For each calendar year in which the 2022 Series B Bonds are outstanding, NCPA, its agents or paying agents or a broker is required to provide the IRS with certain information, including a holder's name, address and taxpayer identification number (either the holder's Social Security number or its employer identification number, as the case may be), the aggregate amount of principal and interest paid to that holder during the calendar year and the amount of tax withheld, if any. This obligation, however, does not apply with respect to certain U.S. Holders, including corporations, tax-exempt organizations, qualified pension and profit sharing trusts, and individual retirement accounts and annuities.

If a U.S. Holder subject to the reporting requirements described above fails to supply its correct taxpayer identification number in the manner required by applicable law or under-reports its tax liability, NCPA, its agents or paying agents or a broker may be required to make "backup" withholding of tax on each payment of interest or principal on the 2022 Series B Bonds. This backup withholding is not an additional tax and may be credited against the U.S. Holder's federal income tax liability, provided that the U.S. Holder furnishes the required information to the IRS.

Under current Treasury Regulations, backup withholding and information reporting will not apply to payments of interest made by NCPA, its agents (in their capacity as such) or paying agents or a broker to a Non-U.S. Holder if such holder has provided the required certification that it is not a U.S. person (as set forth in the second paragraph under "– Non-U.S. Holders" above), or has otherwise established an exemption (provided that neither NCPA nor its agent has actual knowledge that the holder is a U.S. person or that the conditions of an exemption are not in fact satisfied).

Payments of the proceeds from the sale of a 2022 Series B Bond to or through a foreign office of a broker generally will not be subject to information reporting or backup withholding. However, information reporting (but not backup withholding) may apply to those payments if the broker is one of the following:

- a U.S. person;
- a controlled foreign corporation for U.S. tax purposes;
- a foreign person 50-percent or more of whose gross income from all sources for the three-year period ending with the close of its taxable year preceding the payment was effectively connected with a United States trade or business; or

- a foreign partnership with certain connections to the United States.

Payment of the proceeds from a sale of a 2022 Series B Bond to or through the United States office of a broker is subject to information reporting and backup withholding unless the holder or beneficial owner certifies as to its taxpayer identification number or otherwise establishes an exemption from information reporting and backup withholding.

The preceding federal income tax discussion is included for general information only and may not be applicable depending upon a holder's particular situation. Holders should consult their tax advisors with respect to the tax consequences to them of the purchase, ownership and disposition of the 2022 Series B Bonds, including the tax consequences under federal, state, local, foreign and other tax laws and the possible effects of changes in those tax laws.

State Taxes. Special Tax Counsel is of the opinion that interest on the 2022 Series B Bonds is exempt from personal income taxes of the State of California under present State law. Special Tax Counsel expresses no opinion as to other state or local tax consequences arising with respect to the 2022 Series B Bonds nor as to the taxability of the 2022 Series B Bonds or the income therefrom under the laws of any state other than California.

IN ALL EVENTS, ALL INVESTORS SHOULD CONSULT THEIR OWN TAX ADVISORS IN DETERMINING THE FEDERAL, STATE, LOCAL, FOREIGN AND OTHER TAX CONSEQUENCES TO THEM OF THE PURCHASE, OWNERSHIP AND DISPOSITION OF THE 2022 SERIES B BONDS.

Considerations for ERISA and Other U.S. Benefit Plan Investors. The Employee Retirement Income Security Act of 1974, as amended ("ERISA"), imposes certain fiduciary obligations and prohibited transaction restrictions on employee pension and welfare benefit plans subject to Title I of ERISA ("ERISA Plans"). Section 4975 of the Code imposes essentially the same prohibited transaction restrictions on tax-qualified retirement plans described in Section 401(a) and 403(a) of the Code, which are exempt from tax under Section 501(a) of the Code, other than governmental and church plans as defined herein ("Qualified Retirement Plans"), and on Individual Retirement Accounts ("IRAs") described in Section 408(b) of the Code (collectively, "Tax-Favored Plans"). Certain employee benefit plans such as governmental plans (as defined in Section 3(32) of ERISA) ("Governmental Plans"), and, if no election has been made under Section 410(d) of the Code, church plans (as defined in Section 3(33) of ERISA) ("Church Plans"), are not subject to ERISA requirements. Additionally, such Governmental and Church Plans are not subject to the requirements of Section 4975 of the Code but may be subject to applicable federal, state or local law ("Similar Laws") which is, to a material extent, similar to the foregoing provisions of ERISA or the Code. Accordingly, assets of such plans may be invested in the 2022 Series B Bonds without regard to the ERISA and Code considerations described below, subject to the provisions of Similar Laws.

In addition to the imposition of general fiduciary obligations, including those of investment prudence and diversification and the requirement that a plan's investment be made in accordance with the documents governing the plan, Section 406 of ERISA and Section 4975 of the Code prohibit a broad range of transactions involving assets of ERISA Plans and Tax-Favored Plans and entities whose underlying assets include plan assets by reason of ERISA Plans or Tax-Favored Plans investing in such entities (collectively, "Benefit Plans") and persons who have certain specified relationships to the Benefit Plans ("Parties In Interest" or "Disqualified Persons"), unless a statutory or administrative exemption is available. The definitions of "Party in Interest" and "Disqualified Person" are expansive. While other entities may be encompassed by these definitions, they include, most notably: (1) fiduciary with respect to a plan; (2) a person providing services to a plan; (3) an employer or employee organization any of whose employees or members are covered by the plan; and (4) the owner of an IRA. Certain Parties in Interest (or Disqualified Persons) that participate in a prohibited transaction may be subject to a penalty (or an excise tax) imposed pursuant to Section 502(i) of ERISA (or Section 4975 of the Code) unless a statutory or administrative exemption is available. Without an exemption an IRA owner may disqualify his or her IRA.

Certain transactions involving the purchase, holding or transfer of the 2022 Series B Bonds might be deemed to constitute prohibited transactions under ERISA and Section 4975 of the Code if assets of NCPA were deemed to be assets of a Benefit Plan. Under final regulations issued by the United States Department of Labor (the "Plan Assets Regulation"), the assets of NCPA would be treated as plan assets of a Benefit Plan for the purposes of ERISA and Section 4975 of the Code if the Benefit Plan acquires an "equity interest" in NCPA and none of the exceptions contained in the Plan Assets Regulation is applicable. An equity interest is defined under the Plan Assets Regulation as an interest in an entity other than an instrument which is treated as indebtedness under applicable local law and which has no substantial equity features. Although there can be no assurances in this regard, it appears that the 2022 Series B Bonds should be treated as debt without substantial equity features for purposes of the Plan Assets Regulation. This determination is based upon the traditional debt features of the 2022 Series B Bonds, including the reasonable expectation of purchasers of 2022 Series B Bonds that the 2022 Series B Bonds will be repaid when due, traditional default remedies, as well as the absence of conversion rights, warrants and other typical equity features. The debt treatment of the 2022 Series B Bonds for ERISA purposes could change subsequent to issuance of the 2022 Series B Bonds. In the event of a withdrawal or downgrade to below investment grade of the rating of the 2022 Series B Bonds or a characterization of the 2022 Series B Bonds as other than indebtedness under applicable local law, the subsequent purchase of the 2022 Series B Bonds or any interest therein by a Benefit Plan is prohibited.

However, without regard to whether the 2022 Series B Bonds are treated as an equity interest for such purposes, though, the acquisition or holding of 2022 Series B Bonds by or on behalf of a Benefit Plan could be considered to give rise to a prohibited transaction if NCPA or the Trustee, or any of their respective affiliates, is or becomes a Party in Interest or a Disqualified Person with respect to such Benefit Plan.

Most notably, ERISA and the Code generally prohibit the lending of money or other extension of credit between an ERISA Plan or Tax-Favored Plan and a Party in Interest or a Disqualified Person, and the acquisition of any of the 2022 Series B Bonds by a Benefit Plan would involve the lending of money or extension of credit by the Benefit Plan. In such a case, however, certain exemptions from the prohibited transaction rules could be applicable depending on the type and circumstances of the plan fiduciary making the decision to acquire a 2022 Series B Bond. Included among these exemptions are: Prohibited Transaction Class Exemption ("PTCE") 96-23, regarding transactions effected by certain "in-house asset managers"; PTCE 90-1, regarding investments by insurance company pooled separate accounts; PTCE 95-60, regarding transactions effected by "insurance company general accounts"; PTCE 91-38, regarding investments by bank collective investment funds; and PTCE 84-14, regarding transactions effected by "qualified professional asset managers." Further, the statutory exemption in Section 408(b)(17) of ERISA and Section 4975(d)(20) of the Code provides for an exemption for transactions involving "adequate consideration" with persons who are Parties in Interest or Disqualified Persons solely by reason of their (or their affiliate's) status as a service provider to the Benefit Plan involved and none of whom is a fiduciary with respect to the Benefit Plan assets involved (or an affiliate of such a fiduciary). There can be no assurance that any class or other exemption will be available with respect to any particular transaction involving the 2022 Series B Bonds, or that, if available, the exemption would cover all possible prohibited transactions.

By acquiring a 2022 Series B Bond (or interest therein), each purchaser and transferee (and if the purchaser or transferee is a plan, its fiduciary) is deemed to (a) represent and warrant that either (i) it is not acquiring the 2022 Series B Bond (or interest therein) with the assets of a Benefit Plan, Governmental plan or Church plan; or (ii) the acquisition and holding of the 2022 Series B Bond (or interest therein) will not give rise to a nonexempt prohibited transaction under Section 406 of ERISA or Section 4975 of the Code or Similar Laws, and (b) acknowledge and agree that a Benefit Plan, Governmental plan or Church plan subject to Similar Laws may not purchase the 2022 Series B Bonds (or any interest therein) at any time that the ratings on the 2022 Series B Bonds are withdrawn or downgraded to below investment grade or the 2022 Series B Bonds have been characterized as other than indebtedness for applicable local law purposes. A purchaser or transferee who acquires 2022 Series B Bonds with assets of a Benefit Plan represents that such purchaser or transferee has considered the fiduciary requirements of ERISA, the Code or Similar Laws and has consulted with counsel with regard to the purchase or transfer.

In addition, each purchaser and each transferee (and if the purchaser or transferee is a Benefit Plan, its fiduciary) of a 2022 Series B Bond that is a Benefit Plan is deemed to represent and warrant that: (a) the decision to acquire the 2022 Series B Bonds was made by the plan fiduciary; (b) the plan fiduciary is independent of NCPA, the Trustee, and the Underwriters; (c) the plan fiduciary meets the requirements of 29 C.F.R. § 2510.3 21(c)(1) and specifically is either a bank as defined in Section 202 of the Investment Advisers Act of 1940 or similar institution that is regulated and supervised and subject to periodic examination by a U.S. state or U.S. federal agency; an insurance carrier which is qualified under the laws of more than one U.S. state to perform the services of managing, acquiring or disposing of assets of a Benefit Plan; an investment adviser registered under the Investment Advisers Act of 1940 or, if not registered as an investment adviser under the Investment Advisers Act by reason of paragraph(1) of Section 203A of the Investment Advisers Act, is registered as an investment adviser under the laws of the U.S. state in which it maintains its principal office and place of business; a broker dealer registered under the Exchange Act; or holds, or has under its management or control, total assets of at least $50 million (provided that this clause shall not be satisfied if the plan fiduciary is an individual directing his or her own individual plan account or is a relative of such individual); (d) the plan fiduciary is capable of evaluating investment risks independently, both in general and with regard to particular transactions, and investment strategies, including the purchase or transfer of the 2022 Series B Bonds; (e) the plan fiduciary is a "fiduciary" with respect to the plan within the meaning of Section (21) of ERISA, Section 4975 of the Code, or both, and is responsible for exercising independent judgment in evaluating the acquisition, transfer or holding of the 2022 Series B Bonds; (f) none of NCPA, the Trustee, or the Underwriters has exercised any authority to cause the Benefit Plan to invest in the 2022 Series B Bonds or to negotiate the terms of the Benefit Plan's investment in the 2022 Series B Bonds; and (g) the plan fiduciary has been informed: (1) that none of NCPA, the Trustee, or the Underwriters are undertaking to provide impartial investment advice or to give advice in a fiduciary capacity in connection with the plan's acquisition or transfer of the 2022 Series B Bonds and (2) of the existence and nature of NCPA's, the Trustee's, or the Underwriters' financial interests in the Benefit Plan's acquisition or transfer of the 2022 Series B Bonds.

None of NCPA, the Trustee, or the Underwriters is undertaking to provide impartial investment advice or to give advice in a fiduciary capacity in connection with the acquisition or transfer of the 2022 Series B Bonds by any Benefit Plan.

Because NCPA, the Trustee, the Underwriters or any of their respective affiliates may receive certain benefits in connection with the sale of the 2022 Series B Bonds, the purchase of the 2022 Series B Bonds using plan assets of a Benefit Plan over which any of such parties has investment authority or provides investment advice for a direct or indirect fee may be deemed to be a violation of the prohibited transaction rules of ERISA or Section 4975 of the Code or Similar Laws for which no exemption may be available. Accordingly, any investor considering a purchase of 2022 Series B Bonds using plan assets of a Benefit Plan should consult with its counsel if NCPA, the Trustee or the Underwriters or any of their respective affiliates has investment authority or provides investment advice for a direct or indirect fee with respect to such assets or is an employer maintaining or contributing to the Benefit Plan.

Any ERISA Plan fiduciary considering whether to purchase the 2022 Series B Bonds on behalf of an ERISA Plan should consult with its counsel regarding the applicability of the fiduciary responsibility and prohibited transaction provisions of ERISA and Section 4975 of the Code to such an investment and the availability of any of the exemptions referred to above. Persons responsible for investing the assets of Tax-Favored Plans that are not ERISA Plans should seek similar counsel with respect to the prohibited transaction provisions of the Code and the applicability of any similar state or federal law.

CONTINUING DISCLOSURE

General

NCPA and the Significant Share Project Participants have each agreed, pursuant to Continuing Disclosure Agreements with the Trustee, to provide to the Municipal Securities Rulemaking Board (the "MSRB") through its Electronic Municipal Market Access System (the "EMMA System") a copy of their respective annual audited financial statements, as well as certain operating data relating to the Project and the Significant Share Project Participants' respective electric systems. Such audited financial statements are required to be prepared in accordance with generally accepted accounting principles. NCPA will provide to the MSRB through the EMMA System such Project information and its financial statements (unaudited if audited financial statements are not then available) within 180 days after the end of its fiscal year, and each Significant Share Project Participants will provide to the MSRB through the EMMA System their respective financial statements (unaudited if audited financial statements are not then available) and operating data relating to their respective electric systems within 210 days after the end of their respective fiscal years. If unaudited financial statements are provided, audited financial statements will be provided as soon as available. In addition, NCPA and the Significant Share Project Participants have agreed to give timely notice to the MSRB through the EMMA System, of the occurrence of certain specified events. These agreements have been made in order to assist the Underwriters in complying with Securities and Exchange Commission ("SEC") Rule 15c2-12(b)(5) (the "Rule"). See "APPENDIX E–PROPOSED FORMS OF CONTINUING DISCLOSURE AGREEMENTS."

A review of NCPA's and the Significant Share Project Participants' compliance with prior continuing disclosure undertakings during the last five years indicates that:

(1) NCPA did not timely file specified event notices for certain rating changes and did not file specified event notices for rating changes of certain insured bonds resulting from changes in the bond insurer's credit rating.

(2) [In certain instances, Alameda filed its annual continuing disclosure report after the date required for such filing and/or filed a report which omitted certain information Alameda had covenanted to provide in prior undertakings. Specifically, Alameda's annual reports for Fiscal Year [2014] in connection with its electric system obligations, including in connection with bonds issued by NCPA, were not filed, or were not filed with all required information, until ranging from approximately [16 days to up to approximately 86 days] after the respective dates required for such filings. In addition, Alameda did not always provide rating change notices in a timely manner, and did not provide, in a timely manner after the annual filing dates, any notices of the failure to provide annual financial information.] *{Update}*

(3) [For Fiscal Year 2018, the financial and operating data to be filed as part of Lodi's continuing disclosure annual report in connection with certain of Lodi's obligations, [including in

connection with NCPA bonds and Lodi's direct electric system obligations], was not filed until up to approximately 24 days after the date required for certain of such filings.] *{Confirm}*

(4) In certain instances, Palo Alto's filed its annual continuing disclosure report after the date required for such filing and/or filed a report which omitted certain information Palo Alto had covenanted to provide in prior undertakings. Specifically, Palo Alto's annual filings for Fiscal Years [2016 and 2017] in connection with certain outstanding utility revenue bonds of Palo Alto omitted certain information relating to the top ten customers of its gas system. For Fiscal Years [2016, 2017 and 2018], Palo Alto's annual report was not properly associated (or not properly initially associated) on EMMA with the CUSIPs for all applicable Palo Alto bonds. [In 2016, in connection with the economic defeasance of portions of certain bonds, the filing of the notices of such defeasance was not timely; about a month after the event.][Palo Alto has established internal policies to ensure that future filings are made as required.] *{Update}*

(5) [The annual reports required for Fiscal Year 2015 for certain of Roseville's then-outstanding obligations were not filed, or were not filed with all required information, until up to approximately 48 days after the dates required for such filings.] Roseville has not in a timely manner filed all significant event notices, including, but not limited to, notices of changes in the ratings of certain then-outstanding obligations resulting from changes in ratings to the bond insurers who insured such obligations or the underlying ratings for such obligations. Roseville has engaged contract support for the preparation and filing of its continuing disclosure reports in order to ensure compliance with future continuing disclosure obligations. *{Update}*

(6) Finally, all filings made by NCPA and each of the Significant Share Project Participants have not always been associated, or associated by the required filing deadline, with all CUSIPs for each of the related outstanding obligations.

NCPA and the Significant Share Project Participants (as applicable) believe they have made corrective filings to address the known instances during the last five years of past delayed or failure to file annual reports, omissions of required information and/or rating changes to be filed under their respective prior continuing disclosure undertakings (except with respect to certain bonds or other obligations that are no longer outstanding) and are currently in compliance in all material respects with such prior continuing disclosure undertakings.

[City of Alameda Settlement with Securities and Exchange Commission

In connection with an Offer of Settlement by the City of Alameda dated June 27, 2016, and an Order Instituting Cease-and-Desist Proceedings Pursuant to Section 8A of the Securities Act of 1933, Making Findings, and Imposing Remedial Sanctions and a Cease-and-Desist Order of the United States Securities and Exchange Commission dated August 24, 2016 (the "SEC Order"), the City of Alameda has undertaken to:

> (i) Within 180 days of the entry of the SEC Order, establish appropriate written policies and procedures and periodic training regarding continuing disclosure obligations to effect compliance with the federal securities laws, including the designation of an individual or officer at Alameda responsible for ensuring compliance by Alameda with such policies and procedures and responsible for implementing and maintaining a record (including attendance) of such training.

(ii) Within 180 days of the entry of the SEC Order, comply with existing continuing disclosure undertakings, including updating past delinquent filings if Alameda is not currently in compliance with its continuing disclosure obligations.

For good cause shown, the SEC staff may extend any of the procedural dates relating to the Alameda's undertakings. Deadlines for procedural dates are to be counted in calendar days, except that if the last day falls on a weekend or federal holiday, the next business day shall be considered the last day.

(iv) Disclose in a clear and conspicuous fashion the terms of the settlement in any final official statement for an offering by Alameda within five years of the institution of the SEC's proceedings.

(v) Certify, in writing, compliance with the undertakings set forth above. The certification shall identify the undertakings, provide written evidence of compliance in the form of a narrative, and be supported by exhibits sufficient to demonstrate compliance. The SEC staff may make a reasonable request for further evidence of compliance, and Alameda has agreed to provide such evidence. The certification and supporting material shall be submitted to certain specified SEC personnel no later than the one-year anniversary of an institution of the SEC's proceedings.

(vi) Cooperate with any subsequent investigation by the SEC regarding the false statement(s) and/or material omission(s), including the roles of individuals and/or other parties involved.

Alameda has established procedures to ensure compliance with their continuing disclosure undertakings in the future for Alameda and for all entities that are created or controlled by Alameda; and, as stated above, has made remedial filings of all delinquent or missing information in its prior undertakings for issues currently outstanding. Alameda fully intends to comply with all other requirements of the SEC Order.] *{Delete as more than 5 years ago?}*

RATINGS

Moody's Investors Service and Fitch Ratings have assigned to the 2022 Bonds the ratings of "____" and "____," respectively. No application has been made to any other rating agency in order to obtain additional ratings on the 2022 Bonds. Each credit rating reflect only the view of the organization furnishing the same and is not a recommendation to buy, sell or hold the 2022 Bonds. Explanations of the significance of such ratings may be obtained only from the respective organizations at: Moody's Investors Service, 1 World Trade Center, 250 Greenwich Street, 23rd Floor, New York, New York 10007 and Fitch Ratings, 33 Whitehall Street, New York, New York 10004. Generally, a rating agency bases its rating on the information and materials furnished to it and on investigations, studies and assumptions of its own. There is no assurance that either rating will continue for any given period or that it will not be revised downward or withdrawn entirely by the respective rating agency, if in the judgment of such rating agency, circumstances so warrant. NCPA undertakes no responsibility to oppose any such revision or withdrawal. Any such downward revision or withdrawal of such ratings may have an adverse effect on the market price of the 2022 Bonds.

UNDERWRITING

Citigroup Capital Markets Inc., on behalf of itself and BofA Securities, Inc., underwriters for the 2022 Bonds (the "Underwriters"), has agreed to purchase the 2022 Series A Bonds from NCPA at a price of $__________ (which reflects the $_________ par amount of the 2022 Series A Bonds, plus original issue premium of $_________, and less an Underwriters' discount of $_________) and to purchase the 2022 Series B Bonds from NCPA at a price of $____________ (which reflects the $___________ par amount of the 2022 Series B Bonds less an Underwriters' discount of $______), subject to certain conditions set forth in the Contract of Purchase between NCPA and the Underwriters.

The Underwriters may offer and sell the 2022 Bonds to certain dealers and others at prices lower than the offering prices or at yields higher than the offering yields stated on the inside cover page. The offering prices and yields may be changed from time to time by the Underwriters. The Contract of Purchase for the 2022 Bonds provides that the Underwriters will purchase all of the 2022 Bonds, if any are purchased, the obligation to make such purchases being subject to certain terms and conditions set forth in the Contract of Purchase.

Citigroup Global Markets Inc., one of the Underwriters of the 2022 Bonds, has entered into a retail distribution agreement with Fidelity Capital Markets, a division of National Financial Services LLC (together with its affiliates, "Fidelity"). Under this distribution agreement, Citigroup Global Markets Inc. may distribute municipal securities to retail investors at the original issue price through Fidelity. As part of this arrangement, Citigroup Global Markets Inc. will compensate Fidelity for its selling efforts.

BofA Securities, Inc., the other Underwriter of the 2022 Bonds, has entered into a distribution agreement with its affiliate Merrill Lynch, Pierce, Fenner & Smith Incorporated ("MLPF&S"). As part of this arrangement, BofA Securities, Inc. may distribute securities to MLPF&S, which may in turn distribute such securities to investors through the financial network of MLPF&S. As part of this arrangement, BofA Securities, Inc. may compensate MLPF&S as a dealer for their selling efforts with respect to the 2022 Bonds.

CERTAIN RELATIONSHIPS

The Underwriters and their respective affiliates comprise full service securities firms and commercial banks, among other entities. The Underwriters and their respective affiliates engage in various activities, which may include sales and trading, commercial and investment banking, advisory, investment management, investment research, principal investment, hedging, market making, brokerage and other financial and non-financial activities and services. Under certain circumstances, the Underwriters and their affiliates may have certain creditor and/or other rights against NCPA and its members in connection with such activities.

In the course of their various business activities, the Underwriters and their affiliates may purchase, sell or hold a broad array of investments and actively trade securities, derivatives, loans, commodities, currencies, credit default swaps and other financial instruments for their own account and for the accounts of their customers, and such investment and trading activities may involve or relate to assets, securities and/or instruments of NCPA (directly, as collateral securing other obligations or otherwise) and/or persons and entities with relationships with NCPA, including its members. An affiliate of Citigroup Global Markets Inc., one of the Underwriters of the 2022 Bonds, serves as the counterparty to the 2008 Series A Hydroelectric Swap that is being terminated in connection with the issuance of the 2022 Bonds. The termination of the 2008 Series A Hydroelectric Swap will result in NCPA making a termination payment to CFPI, an affiliate of such Underwriter.

The Underwriters and their affiliates may also communicate independent investment recommendations, market advice or trading ideas and/or publish or express independent research views in respect of such assets, securities or instruments and may at any time hold, or recommend to clients that they should acquire, long and/or short positions in such assets, securities and instruments.

MUNICIPAL ADVISOR

PFM Financial Advisors LLC (the "Municipal Advisor") has assisted NCPA with various matters relating to the planning, structuring and delivery of the 2022 Bonds. The Municipal Advisor is a financial advisory firm and is not engaged in the business of underwriting or distributing municipal securities or other public securities. The Municipal Advisor assumes no responsibility for the accuracy, completeness or fairness of this Official Statement. The Municipal Advisor will receive compensation from NCPA contingent upon the sale of the delivery of the 2022 Bonds.

APPROVAL OF LEGAL PROCEEDINGS

The issuance of the 2022 Bonds is subject to the approval of legality of Stradling Yocca Carlson & Rauth, a Professional Corporation, Bond Counsel to NCPA. Certain legal matters will be passed upon for NCPA by Jane E. Luckhardt, Esq., General Counsel to NCPA, and by Spiegel & McDiarmid LLP, Washington, D.C., Washington Counsel to NCPA. Nixon Peabody LLP is serving as Special Tax Counsel to NCPA in connection with the 2022 Bonds. Stradling Yocca Carlson & Rauth, a Professional Corporation, is serving as Disclosure Counsel to NCPA in connection with the 2022 Bonds. Certain legal matters will be passed upon for the Underwriters by Orrick, Herrington & Sutcliffe LLP, Counsel to the Underwriters.

VERIFICATION OF MATHEMATICAL COMPUTATIONS

On the date of delivery of the 2022 Bonds, NCPA will receive a report from _____________, _________, ________ (the "Verification Agent") verifying the adequacy of the cash deposited and held in the 2012 Series A Refunding Escrow Fund, together with the maturing principal amounts of and interest earned on the Escrow Securities (if any), to pay on the redemption date therefor, the redemption price of the Refunded 2012 Series A Bonds and accrued interest thereon.

The report of the Verification Agent will include the statement that the scope of their engagement was limited to verifying the mathematical accuracy of the computations contained in the schedules provided to them and that they have no obligations to update their report because of events occurring, or data or information coming to their attention, subsequent to the date of their report.

INDEPENDENT AUDITORS

The combined financial statements of Northern California Power Agency and Associated Power Corporations as of and for the years ended June 30, 2021 and 2020 have been audited by Baker Tilly US, LLP, independent auditors, as stated in their report appearing therein. Baker Tilly US, LLP has not been engaged to perform and has not performed, since the date of its report included therein, any procedures on the financial statements addressed in such report. Baker Tilly US, LLP has also not performed any procedures relating to this Official Statement.

INCLUSION BY SPECIFIC REFERENCE

When delivered by the Underwriters, in their capacity as such, this Official Statement shall be deemed to include by specific reference all documents previously provided to the MSRB (through its EMMA System) by NCPA or a Significant Share Project Participant with respect to its electric system to the extent that statements in such documents are material to the offering made hereby. Any statements in a document included by specific reference herein shall be modified or superseded for purposes of this Official Statement to the extent that it is modified or superseded by statements contained in this Official Statement or in any other subsequently provided document included by specific reference herein.

MISCELLANEOUS

This Official Statement includes descriptions of the terms of the 2022 Bonds, the Indenture, the Escrow Agreement, the Third Phase Agreement, the Continuing Disclosure Agreements, certain other agreements and certain provisions of state and federal legislation. Such descriptions do not purport to be complete and all such descriptions and references thereto are qualified in their entirety by references to each such document, copies of which may be obtained from NCPA or, during the period of the offering, from the Underwriters.

Any statements herein involving matters of opinion, whether or not expressly so stated, are intended as such and not as representations of fact.

NORTHERN CALIFORNIA POWER AGENCY

By: ____

Randy S. Howard
General Manager

APPENDIX A

SELECTED INFORMATION RELATING TO THE SIGNIFICANT SHARE PROJECT PARTICIPANTS

The following information has been supplied by the respective Project Participants, and includes selected historical operating data and data taken from their electric system balance sheets. Neither NCPA nor any Project Participant makes any representation as to the accuracy or completeness of this information with respect to any other Project Participants.

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CITY OF ALAMEDA

Introduction

The City of Alameda ("Alameda") is a charter city in the State of California. Alameda is an island community of 22.8 square miles located across the bay from San Francisco and to the west of the City of Oakland. Alameda was incorporated in 1854.

Alameda provides electric utility service through its Department of Public Utilities – Bureau of Electricity. The Alameda Bureau of Electricity began operation in 1887. The Bureau of Electricity did business as "Alameda Power & Telecom" beginning in 1999. On January 26, 2009, the name was changed to "Alameda Municipal Power." The Alameda electric utility was the first municipal electric utility in California and is one of the oldest in the nation.

Alameda Municipal Power (hereinafter, "AMP") serves the entire area of the City of Alameda and has about 86 pole miles of overhead distribution lines and 194 circuit miles of underground distribution lines, 6.8 pole miles of overhead transmission lines, 1.9 circuit miles of underground transmission lines. During fiscal year 2020-21, AMP served an average of 35,661 customers, comprised of an average of 31,352 residential customers, an average of 3,931 commercial customers and an average of 378 public authority and other customers, with a peak demand of approximately 62.7 MW.

AMP joined the Northern California Power Agency ("NCPA") in 1968, is a participant in most NCPA projects, and has procured other power supply resources independently. In addition, NCPA has developed electric scheduling, dispatch and transmission capabilities that are utilized in the provision of AMP's electric utility services. All of AMP's rights to electric energy, capacity, environmental attributes and transmission are scheduled by NCPA and AMP participates in the NCPA power pool. See "NORTHERN CALIFORNIA POWER AGENCY – NCPA Power Pool" in the front part of this Official Statement.

From June 2001 until November 21, 2008, AMP also provided cable television and internet services through its telecommunications system. On November 18, 2008, the City Council of the City of Alameda unanimously authorized the sale of the telecommunications business line effective November 21, 2008. See "– Condensed Operating Results and Selected Balance Sheet Information – Inter-fund Transfers" below.

Only the revenues of AMP's electric system will be available to pay amounts owed by Alameda under the Third Phase Agreement.

AMP is under the policy control of the Alameda Public Utilities Board, in accordance with the Alameda City Charter. The Alameda Public Utilities Board consists of four commissioners appointed by the Mayor with concurrence of the City Council, and the City Manager of Alameda (as an ex-officio member), who may not hold any office on the Board.

Pursuant to the Alameda City Charter, the Alameda Public Utilities Board has the power to control and manage the electric system, including the power to set rates for the services of the electric system. The Alameda Public Utilities Board also establishes goals and policies, approves major purchases and creates the framework for local control of the utility.

AMP's main office is located at 2000 Grand Street, Alameda, California 94501, (510) 748-3900. For more information about AMP and its electric system, contact Nicolas Procos, General Manager at the above address and telephone number. A copy of the most recent annual comprehensive financial report of AMP (the "Annual Report") is available on AMP's website at *http://www.alamedamp.com* and on the

Municipal Securities Rulemaking Board's Electronic Municipal Market Access system at *http://emma.msrb.org/*. The Annual Report is incorporated herein by this reference. However, the information presented on such website or referenced therein other than the Annual Report is not part of this Official Statement and is not incorporated by reference herein.

Power Supply Resources

The following table sets forth information concerning AMP's power supply resources and the energy supplied by each during the fiscal year ended June 30, 2021.

CITY OF ALAMEDA
ALAMEDA MUNICIPAL POWER
POWER SUPPLY RESOURCES
For the Fiscal Year Ended June 30, 2021

Source	Capacity Available (MW)[1]	Actual Energy (GWh)	% of Total Requirements
Purchased Power[2]:			
Western Hydroelectric	17.2	26.2	7.6%
Landfill Gas[4]	8.5	81.2	23.5
High Winds	3.3	21.9	6.3
Silicon Valley Power	--	36.3	10.5
NCPA			
Hydroelectric Project	25.3	21.2	6.1
Combustion Turbine Project No. 1 & 2[3]	24.8	11.1	3.2
Geothermal Plant 1[4]	10.0	78.3	22.7
Geothermal Plant 2[4]	8.9	49.9	14.5
Graeagle	--	1.6	0.5
Other Carbon Free Purchases (Net)	--	17.7	5.1
Total Capacity and Total Purchased Energy[5]	98.0	345.2	103.4
Less Line Losses	--	(11.3)	(3.4)
AMP's Capacity and Retail Sales Requirements	62.7	333.9	100.0%

(1) Non-coincident, maximum net qualifying capacity available for CAISO.
(2) Entitlements, firm allocations and contract amounts.
(3) Combustion Turbine Project No. 2 is also referred to as Unit One or the Capital Facilities Project in the front part of this Official Statement.
(4) AMP sold its share of eligible renewable energy generated by the NCPA Geothermal Project and one of its landfill power purchase agreements. See "– Energy Efficiency and Conservation; Renewable Resources." Total capacity excludes the amounts sold.
(5) Totals may not foot due to rounding.
Source: Alameda Municipal Power.

In the fiscal year ended June 30, 2021, AMP's average cost of power for 333.9 GWh of energy sales was 18.62 cents per kWh, and its average cost of power for the 345.2 GWh purchased was 8.78 cents per kWh.

Purchased Power

Western. AMP has power purchase agreements ("PPAs") with the Western Area Power Administration ("Western") that continue through December 31, 2024. AMP's Western power is assigned to NCPA for scheduling and delivery to AMP. Power purchased under these agreements is generated by the Central Valley Project ("CVP"), a series of federal hydroelectric facilities in Northern California operated by the United States Bureau of Reclamation.

On October 5, 2000, AMP signed a 20-year Base Resource agreement with Western with initial service beginning January 1, 2005. Service under the Western contract will continue through December 31, 2024, with AMP receiving a "slice of the system" allocation from Western. AMP's allocation is currently 1.08075% of the CVP output. Power provided to AMP under the Western contract is on a take-or-pay basis; AMP is obligated to pay its share of Western costs whether or not it receives any power.

On March 10, 2021, AMP executed a 30-year extension of the Western agreement at an increased share of 1.1821% of Base Resource with an effective date of January 1, 2025. Under the power marketing plan, Western will allow an existing customer to reduce its base resource percentage allocation with at least six month's written notice to Western prior to January 1, 2025.

Other Purchases. AMP has also entered into certain other PPAs: (1) a PPA with Avangrid Renewables LLC (formerly Iberdrola Renewables, Inc.) for power supplied from the High Winds Project in Solano County, California under which AMP receives 6.17% (approximately 10 MW of the 162 MW project) until June 30, 2028; (2) four long-term PPAs for power supplied by multiple existing generating facilities utilizing combustible gaseous emissions from landfills located in or near the San Francisco Bay area, under which AMP has received approximately 1.3 MW of baseload power from one facility since 2006, approximately 7.1 MW of baseload output from two additional facilities since 2009, and approximately 1.9 MW of baseload power from a fourth facility since 2013; and (3) a PPA with the City of Santa Clara (Silicon Valley Power) under which AMP receives an additional 10 MW of renewable energy from Silicon Valley Power during the months of January, February, October, November, and December beginning January 2018 through December 2027. In addition, AMP makes short-term clean energy market purchases as necessary to meet its native load requirements.

Generally, AMP has entered into power purchase agreements solely or primarily for use within its own system.

Joint Powers Agency Resources

NCPA. AMP does not independently own any generation assets but, in addition to power purchased from Western and others, AMP is a participant in most NCPA projects. AMP has purchased from NCPA: a 10.00% entitlement share in the NCPA Hydroelectric Project; a 21.820% entitlement share in the NCPA Combustion Turbine Project Number One; a 19.00% entitlement share in the Combustion Turbine Project Number Two (referred to as Unit One or the Capital Facilities Project in this Official Statement); and a 16.8825% entitlement share in the NCPA Geothermal Project. AMP additionally participates in the NCPA Geysers Transmission Project, in which it has a 30.36% entitlement share. For a description of such resources, see "THE HYDROELECTRIC PROJECT" and "OTHER NCPA PROJECTS" in the front part of this Official Statement. For each of these NCPA projects in which AMP participates, AMP is obligated to pay, on an unconditional take-or-pay basis, as an operation and maintenance cost of its electric system, its entitlement share of the debt service on NCPA bonds issued for the project (as applicable), as well as its share of the operation and maintenance expenses of the project. See also "– Indebtedness; Joint Powers Agency Obligations" below.

Through NCPA, AMP also participates in certain PPAs entered into by NCPA, including a PPA with Henwood Associates, Inc. to purchase 100% of the power produced by the Graeagle Hydroelectric Project, a small 440 kW hydroelectric project (replacing a prior agreement under which AMP received 50% of the project output). The energy source for the facility is hydroelectric and the facility meets the qualifying facilities requirements established by FERC. The facility output, which varies with hydrological conditions, has averaged about 2,000 MWh per year. Deliveries under the agreement began on February 1, 2010 and will terminate on January 31, 2030. See also "OTHER NCPA PROJECTS – Power Purchase and Natural Gas Contracts" in the front part of this Official Statement. Additionally, AMP participates in NCPA's Market Purchase Program when contracted resources cannot meet load.

TANC California-Oregon Transmission Project. AMP, together with fourteen other northern California cities and districts and one rural electric cooperative, is a member, or associate member, of a California joint powers agency known as the Transmission Agency of Northern California ("TANC"). TANC, together with the City of Redding ("Redding"), Western, two California water districts and Pacific Gas & Electric Company ("PG&E") (collectively, the "COTP Participants") own the California–Oregon Transmission Project ("COTP"), a 339-mile long, 1,600 MW, 500 kV transmission project between southern Oregon and central California. The COTP was placed in service on March 24, 1993, at an original cost of approximately $430 million. TANC financed its interest in the COTP through the issuance of California-Oregon Transmission Project Revenue Bonds, of which approximately $169.9 million principal amount of revenue bonds was outstanding as of January 31, 2022. See "– Indebtedness."

Pursuant to Project Agreement No. 3 for the COTP (the "TANC Agreement"), TANC has agreed to provide to AMP and 12 other members of TANC (the "TANC Member-Participants") a participation percentage of TANC's entitlement of COTP transfer capability. In return, each TANC Member-Participant has severally agreed to pay TANC a corresponding percentage of TANC's share of the COTP construction costs, including debt service on TANC's outstanding revenue bonds and other obligations issued by TANC to finance its ownership share of the COTP. A TANC Member-Participant's obligations to make payments to TANC are not dependent upon the operation of the COTP and are not subject to reduction. Upon an unremedied default by one TANC Member-Participant in making a payment required under the TANC Agreement, the non-defaulting TANC Member-Participants are required to increase pro-rata their participation percentage by the amount of the defaulting TANC Member-Participant's entitlement share, provided that no such increase can result in a greater than 25% increase in the participation percentage of the non-defaulting TANC Member-Participants.

Pursuant to the TANC Agreement, AMP is obligated to pay 1.23% of TANC's COTP operating and maintenance expenses and 1.33% of TANC's COTP debt service (on bonds other than TANC's 2009 Series A Bonds on which it is obligated for 1.45% of debt service) and is entitled to 1.23% of TANC's share of COTP transfer capability (approximately 17 MW net of third-party layoffs of TANC) on an unconditional take-or-pay basis. However, Alameda has laid off its COTP entitlement through 2039 as described under "– *COTP Long-Term Layoff*" below.

To utilize the full transfer capability of the COTP and the Intertie (described below) on a firm basis between the Pacific Northwest and California, it is necessary to coordinate the operation of all three transmission lines. The Pacific AC Intertie (the "Intertie") is a two line system which, like the COTP, connects California utilities with those in the Pacific Northwest. The Intertie lines are owned by PG&E, PacifiCorp and Western and are operated by the CAISO. Rate schedules are on file with the Federal Energy Regulatory Commission ("FERC") to accomplish this coordination. The three-line system comprised of the COTP and the Intertie is collectively referred to as the California-Oregon Intertie ("COI").

The COTP is operated within the Balancing Authority of Northern California ("BANC"). As a result, the TANC Member-Participants are able to undertake direct scheduling of energy transactions over the COTP within the balancing authority area, free of the CAISO tariff, charges, congestion and encumbrances.

COTP Long-Term Layoff. Due to situational and economic changes in value of power deliveries over the COTP, AMP and six other TANC members laid off their participation shares in the COTP to other TANC members for a period of 25 years with the option to extend for an additional five years upon all parties' approval. The enabling agreement among the parties became effective on July 1, 2014. The agreement transfers the use and associated rights of AMP's project participation shares to the receiving parties (the Modesto Irrigation District, the Turlock Irrigation District and the Sacramento Municipal Utility District). The receiving parties agree to pay the debt service and operating and maintenance costs associated with those shares and an additional value payment after the debt service is retired. Under the agreement, AMP continues to be a member of TANC and remains ultimately responsible for its allocated share of the costs of the COTP in the event of a default by a receiving party during the term of the agreement.

TANC Tesla–Midway Transmission Service. The southern physical terminus of the COTP is near the Tesla Substation of PG&E, located near Tracy, California. The COTP is connected to Western's Tracy and Olinda Substations. PG&E provides TANC and its members with 300 MW of firm bi-directional transmission capacity in its transmission system between its Tesla Substation and its Midway Substation near Buttonwillow, California (the "Tesla-Midway Transmission Service") under a long-term agreement known as the South of Tesla Principles. AMP's share of Tesla-Midway Transmission Service is 6.0 MW. AMP may utilize its full allocation of Tesla–Midway Transmission Service for firm and non-firm power transactions when economic to do so and if available.

Energy Efficiency and Conservation; Renewable Resources

State laws enacted in 2005 and 2006 require publicly-owned utilities ("POUs"), such as AMP, in procuring energy, to first implement all available energy efficiency and demand reduction resources that are cost-effective, reliable and feasible, and to provide annual reports to customers and to the California Energy Commission (the "CEC") describing their investment in energy efficiency and demand reduction programs. California Assembly Bill ("AB") 2021, which became law in 2007, requires investor-owned utilities ("IOUs") and POUs to identify energy efficiency potential and establish annual efficiency targets so that the State can meet the goal of reducing total forecasted electricity consumption by 10% over the ten years.

AMP has a full portfolio of public benefits programs, addressing four areas of concentration: low income assistance programs, renewable energy production, advanced electric technology demonstration, and research and development, as well as energy efficiency programs. It has continually funded new renewable resources including geothermal, wind, landfill gas, and hydroelectric generation.

AMP has had energy efficiency programs in place since the 1990s. These energy efficiency programs focus on the unique end-uses in Alameda with its coastal climate, and the resulting lack of air conditioning load. AMP offers energy efficiency programs for all of its customer classes and has established an aggressive target for reducing future consumption by nearly 12% during the next ten years. *{update?}*

California Senate Bill ("SB") X1-2 required POUs to adopt and implement a renewable energy resource procurement plan to achieve specified targets for serving their retail energy loads from California-eligible renewable energy resources, culminating in a target of serving 33% of their loads with California-eligible renewable energy resources by December 31, 2020. State law enacted in 2015, SB 350, increased California's renewable electricity procurement goal from 33% by 2020 to 50% by 2030 based on Renewables Portfolio Standard ("RPS") eligible resources. State law enacted in 2018, SB 100, accelerates the State's RPS target as established by SB 350 from 50% by 2030 to 60% by 2030 and sets a goal of 100% "clean energy" by the year 2045. See "CERTAIN FACTORS AFFECTING THE ELECTRIC UTILITY

INDUSTRY – State Legislation and Regulatory Proceedings – *California Renewables Portfolio Standard*" in the front part of this Official Statement for more information on SBX1-2, SB 350 and SB 100.

AMP's renewables portfolio consists of its share of NCPA's geothermal and hydroelectric projects as well as PPAs for the purchase of landfill gas-to-energy, wind, and additional hydroelectric generation. All of this generation is considered California-eligible renewable generation with the exception of generation from large (>30 MW) hydroelectric facilities, which do not count towards the State's RPS compliance obligations. SBX1-2 regulations included an RPS target of an average of 20% California-eligible renewable resources used to meet retail sales for Compliance Period 1 (calendar year ("CY") 2011 through CY 2013) which AMP exceeded with an actual average of 25%. AMP also satisfied the RPS targets for Compliance Period 2 (CY 2014 through CY 2016) by meeting the RPS target of a total equal to 20% of retail sales in 2014 and 2015, and 25% of retail sales in 2016. AMP has further met the RPS target for Compliance Period 3 (CY 2017 through CY 2020) of a total equal to 27% of retail sales in 2017, 29% in 2018, 31% in 2019 and 33% in 2020. AMP is positioned to fulfill its RPS compliance requirements under current law through 2030 and beyond with its current portfolio.

In January 2012 and again in January 2015, the Alameda Public Utilities Board adopted a Renewable Energy Sales and Use of Resulting Revenues Policy stating that through 2019, AMP may sell eligible renewable energy not required to comply with the Board-approved RPS Policy. AMP subsequently entered into two sales agreements, the first from October 15, 2012 through December 31, 2016 to the California Department of Water Resources ("CDWR"), and a subsequent sale from January 1, 2017 through December 31, 2019 to Shell Energy North America ("Shell"). For both agreements, AMP sold its share of eligible renewable energy generated by NCPA's geothermal project and generation from one of its landfill gas PPAs. In accordance with the adopted policy, the resulting revenues from these sales were used to support initiatives to reduce greenhouse gas ("GHG") emissions associated with electricity use by AMP's customers. AMP has established a Board designated reserve in accordance with this policy into which all revenues associated with these sales were deposited. Through these sales AMP has been able to fund a variety of GHG emissions reductions programs, like energy efficiency, without raising rates. AMP does not anticipate entering into any additional agreements to sell renewable energy.

To comply with California SB 1305, passed in 1997, which created the Power Source Disclosure program (as subsequently modified), AMP must annually disclose the fuel sources of the electricity it sold to customers the previous CY in the CEC's Power Source Disclosure Report, from which a Power Content Label ("PCL") is generated. Alameda reported that it covered 100% of its electricity sales with power from large hydroelectric projects and California eligible renewable resources on the PCL for 2020 and 2021.

Per AB 32, the Global Warming Solutions Act, AMP is subject to the California Air Resources Board's ("CARB") cap-and-trade program regulations. Each year CARB distributes freely allocated allowances to AMP, which AMP must allocate to the cap-and-trade auction process. Current Alameda Public Utilities Board policy requires AMP to allocate allowances to each quarterly auction, deposit the proceeds into a designated reserve account and use the proceeds to benefit retail ratepayers consistent with the goals of AB 32. See "CERTAIN FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY – State Legislation and Regulatory Proceedings – *California Climate Program*" and "– *Cap-and-Trade Program*" in the front part of this Official Statement.

Future Power Supply Resources

AMP is currently investigating options to meet future resource requirements in an environmentally beneficial manner including additional renewable resources and energy efficiency savings.

Interconnections, Transmission and Distribution Facilities

AMP's electric system is interconnected with PG&E's system at two PG&E substations. AMP owns facilities for the distribution of electric power within the city limits of Alameda, which includes approximately 8.70 miles of 115 kV power lines, approximately 271.8 miles of 12 kV distribution lines (approximately 68% of which are underground) and [eight] ***{confirm}***substations. AMP's electric system experienced approximately 43.7minutes of outage time per customer in fiscal year 2020-21.

Wildfire Risks

AMP does not own or operate any transmission or generation assets. The service area of AMP, which is coterminous with the municipal boundaries of the City of Alameda, is largely an urban area and has no urban wildland interface. Alameda is located in a geographical area classified by the California Public Utilities Commission Fire Threat Map as a "Tier 1" fire-threat area (*i.e.*, not in an area of elevated or extreme risk from utility-associated wildfires). By resolution, on September 17, 2018, the Alameda Public Utilities Board made a wildfire risk determination pursuant to the requirements of SB 1028, and determined that AMP's overhead electrical lines and equipment are located within a geographical area that does not have a significant risk of catastrophic wildfire resulting from AMP's electrical lines and equipment. On November 18, 2019, the Alameda Public Utilities Board approved AMP's wildfire mitigation plan. Pursuant to the requirements of California Senate Bill 901 and Assembly Bill 1054, Alameda has completed its third party independent evaluation. Alameda's wildfire mitigation plan is updated annually, with the most recent updated approved by the Alameda Public Utilities Board on May 17, 2021. See also "CERTAIN FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY – State Legislation and Regulatory Proceedings – *Legislation Relating to Wildfires; Related Risks*" in the front part of this Official Statement.

COVID-19

The spread of the novel strain of coronavirus (and variants thereof) and the disease it causes (now known as "COVID-19") has had significant negative impacts throughout the world, including in California. In 2020, the World Health Organization declared the COVID-19 outbreak to be a pandemic, and states of emergency have been declared by the United States, the State and numerous counties throughout the State. The purpose behind these declarations was to coordinate and formalize emergency actions across federal, state and local governmental agencies, and to proactively prepare for a wider spread of the virus.

On March 19, 2020, in an effort to slow the spread of COVID-19, Governor Newsom issued Executive Order N-33-20 ordering individuals living in the State to stay home or at their place of residence except for specified exceptions, including exceptions for certain sectors of the workforce that were classified as providing essential services and products, which allowed businesses and workers in such sectors to continue to operate on-site operations while Executive Order N-33-20 was effective. On June 11, 2021, Governor Newsom issued two executive orders, which became effective on June 15, 2021, which had the effect of rescinding a majority of the COVID-19-related restrictions and providing a timeline for gradually lifting certain of the other restrictions that were not fully rescinded on June 15, 2021.

During the pandemic, AMP has experienced a decline in electricity demand by the small commercial sector and municipal sector (schools/colleges, public libraries) while electricity usage by the residential sector increased, as might be expected with many retail establishments being closed and people staying home. AMP also experienced an increase in industrial load, which reflects that industrial customers are frequently in critical sector-related businesses, which continued to operate during the pandemic. See "Customers, Energy Sales, Revenues and Demand."

Historically, AMP's annual write-offs for uncollectible accounts have been less than 0.10% of gross billings of the Electric System. Since the onset of the COVID-19 pandemic, write-offs for uncollectible accounts has increased. In fiscal year 2018-19, uncollectible accounts represented approximately 6% of the total receivables balance of $2.4 million. For fiscal year 2019-20, uncollectible accounts increased to approximately 13% of the total receivable balance of $3.6 million. In fiscal year 2020-21, uncollectible accounts represented approximately 11% of the total receivables balance of $4.4 million. To help mitigate the economic impact of COVID-19 and the related governmental regulations on its customers, AMP implemented a payment deferral program, which included the suspension of the disconnection of electric utility services for non-payment of utility bills and suspended all penalties and late payments for a period beginning in March 2020 and extending through April 2022. Utility staff promoted AMP bill savings and financial assistance programs (EASE and HEAP).

AMP was allocated approximately $649,771 under the California Department of Community Services and Development California Arrearage Payment Program ("CAPP"), to aid the accounts that have fallen 60 days behind during the period of March 4, 2020 through June 15, 2021, which in turn is expected by AMP to lower the uncollectible revenue amount. AMP received the funding on December 21, 2021. Residential active and inactive accounts with past due balances were credited 100% of their past due amounts and commercial accounts were credited 33.55% of their past due amount from CAPP funds.

With widespread vaccination currently underway in the United States and many countries worldwide, governmental-imposed stay-at-home orders and restrictions on operations of schools and businesses implemented to respond to and control the outbreak have been eased or eliminated. However, restrictions may be re-imposed in various jurisdictions from time to time as local conditions warrant. Alameda cannot predict whether any reinstatement or expansion of stay-at-home orders and travel or other restrictions will occur or when a full resumption of all economic activity will be achieved. The ultimate impact of COVID-19 on the operations and finances of AMP or the Electric System is unknown and there can be no assurances that COVID-19 will not materially adversely impact the financial condition of AMP or the Electric System in the future. There are many variables that will continue to contribute to the economic impact of the COVID-19 pandemic and the recovery therefrom, including the length of time social distancing measures are in place, the effectiveness of State and federal government relief programs and the timing for containment and treatment, new coronavirus strains, vaccinations efforts and vaccine hesitancy. Alameda cannot predict the extent or duration of such impacts.

Rates and Charges

AMP has the exclusive jurisdiction to set electric rates within its service area by action of the Alameda Public Utilities Board. These rates are not subject to review by any state or federal agency.

AMP's fiscal year 2020-21 average rate per kWh sold for all electric service was 18.77 cents per kWh. The average rate per kWh sold for residential service in fiscal year 2020-21 was 20.74 cents. The average rates for commercial service were 16.89 cents per kWh. AMP's average rate for municipal and public authority service for fiscal year 2020-21 was 18.96 cents per kWh. On April 15, 2019, the Alameda Public Utilities Board approved a 2.50% overall average rate increase for residential and commercial customers for fiscal year 2019-20. This was Alameda's most recent base rate increase. Currently, AMP management estimates that AMP's electric rates are approximately 24.2% below those of PG&E on average.

The following table presents a recent history of AMP's rate changes.

CITY OF ALAMEDA
ALAMEDA MUNICIPAL POWER
ELECTRIC RATE CHANGES

Date	Percent Change (Average)
July 1, 2021	0.00%
July 1, 2020	0.00
July 1, 2019	2.50
July 1, 2018	1.00
July 1, 2017	5.00

Source: Alameda Municipal Power.

Largest Customers

AMP's ten largest electric customers in terms of kWh sales for the fiscal year ended June 30, 2021 accounted for 34.14% of total kWh sales and 31.65% of total revenues. The largest customer accounted for 9.63% of total kWh sales and 8.17% of total revenues. The smallest of the ten largest customers accounted for 2.12% of total kWh sales and 2.22% of revenues.

Customers, Sales, Revenues and Demand

The average numbers of customers, kWh sales, revenues derived from sales by classification of service and peak demand during the five fiscal years 2016-17 through 2020-21, are listed below.

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CITY OF ALAMEDA
ALAMEDA MUNICIPAL POWER
ELECTRIC CUSTOMERS, SALES, REVENUES AND DEMAND

	Fiscal Years Ended June 30				
	2017	**2018**	**2019**	**2020**	**2021**
Number of Customers:					
Residential	30,495	30,625	31,201	31,822	31,937
Commercial Small	3,764	3,778	3,808	3,852	3,870
Commercial Medium	12	12	8	8	10
Public Authority	362	363	358	361	359
Other	15	12	21	24	25
Total Customers	34,648	34,790	35,396	36,067	36,201
Kilowatt-Hour Sales:					
Residential	126,850,402	124,589,523	125,510,907	129,591,566	138,607,950
Commercial Small	172,520,353	168,873,305	164,807,447	166,745,235	146,664,721
Commercial Medium	30,127,960	28,321,180	28,712,440	31,301,090	35,641,270
Public Authority	11,428,198	10,723,565	11,064,277	11,539,236	10,470,953
Other	2,838,825	2,518,330	2,034,011	2,605,615	2,548,136
Total kWh sales	343,765,738	335,025,903	332,129,082	341,782,742	333,933,030
Revenues from Sale of Energy:					
Residential	$21,510,126	$23,902,788	$24,414,010	$25,933,443	$27,946,417
Commercial Small	27,177,335	28,500,186	28,354,299	29,341,107	26,015,342
Commercial Medium	4,366,885	4,338,898	4,580,711	5,069,275	5,845,303
Public Authority	1,958,154	1,965,664	2,225,142	2,238,296	2,058,753
Other	913,247	793,870	1,453,471	149,514	320,052
Total Revenues from Sale of Energy	$55,925,747	$59,501,406	$61,027,633	$62,731,635	$62,185,867
Peak Demand (kW)	63,738	59,624	54,362	61,990	62,664

Source: Alameda Municipal Power.

Service Area

Population. The City of Alameda is located in Alameda County just west of the City of Oakland and approximately 12 miles east of San Francisco. The service area of the AMP electric system is coterminous with the city boundaries. Shown below is certain population data for the City of Alameda, the County of Alameda and the State of California.

CITY OF ALAMEDA, COUNTY OF ALAMEDA,
STATE OF CALIFORNIA POPULATION
(1970-2010 as of April 1; 2011-2021 as of January 1)

Year	City of Alameda	County of Alameda	State of California
1970	70,968	1,071,446	19,971,069
1980	63,852	1,105,379	23,667,764
1990	76,459	1,279,182	29,760,021
2000	72,259	1,443,741	33,871,653
2010	73,812	1,510,271	37,253,956
2011	74,477	1,525,761	37,561,624
2012	75,482	1,545,917	37,924,661
2013	76,878	1,569,989	38,269,864
2014	77,500	1,590,729	38,556,731
2015	78,381	1,613,319	38,865,532
2016	80,386	1,631,230	39,103,587
2017	80,947	1,644,303	39,352,398
2018	81,195	1,651,760	39,519,535
2019	81,457	1,659,608	39,605,361
2020	81,135	1,663,114	39,648,938
2021	80,884	1,656,591	39,466,855

Sources: 1970-2010, as of April 1, based on historical U.S. Census population data compiled by the California State Department of Finance. 2011-2021, as of January 1, State of California, Department of Finance, E-4 Population Estimates for Cities, Counties and the State, with 2010 Census Benchmark. Sacramento, California, May 2021.

Employment. Alameda is part of the highly urbanized East Bay, which consists of Alameda and Contra Costa counties. A highly skilled labor force, excellent transportation facilities, renowned educational institutions and available advanced research and development resources contribute to the area's economy. The largest employers in Alameda as of June 30, 2021 are as follows:

CITY OF ALAMEDA
2020-21 LARGEST EMPLOYERS

Employer	Business	Number of Employees
Penumbra, Inc.	Med. Device Developer/Manufacturer	2,244
Alameda Unified School district	Public School	1,018
The North Face	Retail Store	859
Alameda County Medical Center	Medical	746
Telecare Corp.	Medical	695
Abbott Diabetes Care Inc.	Medical Devices	600
City of Alameda	Governmental Entity	538
Exelixis	Biotech	484
Kaiser Foundation Health Plan Inc.	Medical	448
U.S. Department of Transportation	Governmental Entity	368

Source: City of Alameda Community Development Department and City of Alameda Business License Records

The Oakland-Hayward-Berkeley Metropolitan Division, as defined by the State Employment Development Department, includes all cities within Alameda and Contra Costa Counties. According to the California Employment Development Department, the County of Alameda's unemployment rate was 8.5%

for the year 2020. The following table sets forth certain information regarding employment in the City of Alameda from 2016 through 2020.

CITY OF ALAMEDA
CIVILIAN LABOR FORCE, EMPLOYMENT AND UNEMPLOYMENT
2016 TO 2020[(1)(2)]

	2016	2017	2018	2019	2020
Civilian Labor Force	41,500	41,700	41,300	41,400	39,400
Employment	39,800	40,200	40,100	40,300	36,000
Unemployment	1,600	1,400	1,200	1,100	3,300
Unemployment Rate	4.0%	3.5%	2.9%	2.6%	8.5%

(1) Annual averages; not seasonally adjusted. Data may not add due to rounding. Unemployment rates calculated using unrounded data..
(2) Reflects March 2019 benchmark.
Source: State of California Employment Development Department, Labor Market Information Division, Monthly Labor Force Data for Cities and Census Designated Places, Annual Averages – Revised.

Assessed Valuation. The five-year history of assessed valuations in Alameda is as follows.

CITY OF ALAMEDA
TOTAL ASSESSED VALUATIONS
(Fiscal Years 2016-17 through 2020-21)

2016-17	2017-18	2018-19	2019-20	2020-21
$11,858,309,875	$12,544,972,055	$13,543,528,162	$14,580,243,935	$15,501,890,595

Source: City of Alameda Finance Department.

Forecast of Capital Expenditures

AMP's current five-year capital plan for electric facilities contemplates capital expenditures in the following years and amounts:

CITY OF ALAMEDA
ALAMEDA MUNICIPAL POWER
ESTIMATED CAPITAL EXPENDITURES
[Preliminary Info. To be updated]

Fiscal Year Ended June 30,				
2022	2023	2024	2025	2026
$3,852,162	$8,028,873	$4,992,298	$3,325,090	$2,431,502

Source: Alameda Municipal Power.

The capital expenditures are for distribution system improvements and extensions, the underground conversion program, additions for new loads, replacements and maintenance, computer equipment and software and vehicles. AMP anticipates funding the majority of such costs from current year revenues and designated reserves.

Indebtedness; Joint Powers Agency Obligations

As of January 31, 2022, AMP had outstanding obligations under an Installment Sale Agreement, dated as of August 1, 2010 (the "Electric System Installment Sale Agreement"), by and between the Alameda Public Financing Authority and AMP, in the aggregate principal amount of $18,560,000. The installment payments payable by AMP under the Electric System Installment Sale Agreement are payable from and secured solely by a pledge of and lien on net revenues of the electric system of AMP. These obligations are subordinate to the payments required to be made with respect to AMP's obligations to NCPA and TANC as described below.

As previously discussed, AMP participates in certain joint powers agencies, including NCPA and TANC. Obligations of AMP with respect to TANC and NCPA constitute operating expenses of the AMP electric system payable prior to any of the payments required to be made by AMP under the Electric System Installment Sale Agreement described above. The agreements with NCPA and TANC 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. Certain of these agreements contain "step up" provisions obligating AMP to pay a share of the obligations of a defaulting participant. AMP'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.

CITY OF ALAMEDA
ALAMEDA MUNICIPAL POWER
OUTSTANDING DEBT OF JOINT POWERS AGENCIES
(Dollar Amounts in Millions)
(As of January 1, 2022)

	Outstanding Debt[(1)]	AMP's Participation[(2)]	AMP's Share of Outstanding Debt[(1)]
NCPA			
Geothermal Project	$10.8	16.8825%	$ 1.8
Hydroelectric Project	223.3	10.0000	22.3
Capital Facilities Project Unit One	13.8	19.0000	2.6
TANC – South of Tesla	169.9	2.1040	0.1[(3)]
TOTAL*	$417.8		$26.8

* Columns may not add to totals due to independent rounding.
(1) Principal only. Does not include obligation for payment of interest on such debt.
(2) Participation obligation is subject to increase upon default of another project participant. Such increase shall not exceed, without written consent of a non-defaulting participant, an accumulated maximum of 25% of such non-defaulting participant's original participation.
(3) AMP's 1.23% participation share of TANC COTP entitlement has been assigned to other TANC Members. Excludes associated debt obligation. Alameda remains contractually obligated for its share to the extent not paid by assignees. Obligation shown represents portion of TANC COTP debt allocated to Tesla-Midway Transmission Service.
Source: Alameda Municipal Power.

AMP estimates its payment obligations for debt service on its joint powers agency debt obligations to be approximately $3.1million for the fiscal year ended June 30, 2020, and approximately $3.5 million for the fiscal year ended June 30, 2021. A portion of the joint powers agency debt obligations are variable rate debt, liquidity support for which is provided through liquidity arrangements with banks. Unreimbursed draws under liquidity arrangements supporting joint powers agency variable rate debt obligations bear interest at a maximum rate substantially in excess of the current interest rates on such obligations. Moreover, in certain circumstances, the failure to reimburse draws on the liquidity agreements may result in the acceleration of scheduled payment of the principal of such variable rate joint powers agency obligations. To the extent a joint powers agency has entered into interest rate swap agreements for the purposes of substantially fixing the interest cost with respect to variable rate joint powers agency obligations, there is no guarantee that the floating rate payable to such joint powers agency pursuant to such interest rate swap agreements will match the variable interest rate on the associated variable rate joint powers agency debt obligations to which the respective interest rate swap agreement relates at all times or at any time. Under certain circumstances, the swap provider may be obligated to make payments to the joint powers agency under their respective interest rate swap agreement that is less than the interest due on the associated variable rate joint powers agency debt obligations to which such interest rate swap agreement relates. In such event, such insufficiency will be payable from the obligated joint powers agency members (a corresponding amount of which proportionate to its debt service obligations to such joint powers agency could be due from Alameda). In addition, under certain circumstances, each of the swap agreements is subject to early termination, in which event the joint powers agency could be obligated to make a termination payment to the applicable swap provider (a corresponding amount of which proportionate to its debt service obligations to such joint powers agency could be due from Alameda). The only currently outstanding interest rate swap agreement related to Alameda's variable rate joint powers agency debt obligations is the 2008 Series A Hydroelectric Swap which is expected to be terminated in connection with the issuance of the 2022 Bonds. See "PLAN OF REFUNDING" in the front part of this Official Statement.

Transfers to the General Fund

The Alameda City Charter provided for certain excess earnings of the electric system after payment of bond interest and sinking fund requirements and operating expenses (exclusive of depreciation) and certain amounts authorized to be retained by AMP from earnings of the electric system, to be transferred from AMP to the City General Fund, all as defined in and provided pursuant to the terms of the City Charter.

Effective July 1, 2017, and each year thereafter, the Alameda City Charter provides that AMP shall annually transfer to the City General Fund the amount of $3,700,000 plus an adjustment for inflation, minus any deduction for the amount of any exemptions granted by the AMP Board pursuant to the City Charter, in twelve equal monthly installments.

The following table sets out the transfers from the AMP electric system to the Alameda General Fund for the five fiscal years 2016-17 through 2020-21.

CITY OF ALAMEDA
ALAMEDA MUNICIPAL POWER
TRANSFERS TO THE GENERAL FUND

Fiscal Year	Transfer Amount
2016-17	$2,800,000
2017-18	3,700,000
2018-19	3,818,400
2019-20	4,012,000
2020-21	4,029,765

Source: Alameda Municipal Power.

Employees

Labor Relations. As of June 30, 2021, approximately 87 City of Alameda employees were assigned specifically to the Alameda electric utility. AMP's management personnel are represented by the Electric Utility Professionals of Alameda ("EUPA"). Non-management personnel are represented either by the International Brotherhood of Electrical Workers ("IBEW") or the Alameda City Employees Association ("ACEA"). The current Memoranda of Understanding ("MOU") with each of EUPA, ACEA and IBEW expires June 30, 2022. There have been no strikes or other work stoppages at the City of Alameda, including AMP, since the early 1970s.

Pension Plans. Retirement benefits to City of Alameda employees, including those assigned to AMP, are provided through the City of Alameda's participation in the California Public Employees Retirement System ("CalPERS"), an agent multiple employer defined benefit pension plan which acts as a common investment and administrative agent for its participating plan members. Copies of the CalPERS annual financial report may be obtained from the CalPERS Executive Office, 400 Q Street, Sacramento, California 95814.

Alameda's defined benefit pension plans, the Miscellaneous Plan and the Safety Plan of the City of Alameda, provide retirement and disability benefits, annual cost-of-living adjustments, and death benefits to plan members and beneficiaries for substantially all Alameda employees. Benefit provisions under the plans are established by State statute and City resolution. AMP employees participate in the Miscellaneous Plan. No employees assigned to AMP participate in the Safety Plan. Alameda allocates a portion of the net pension liability, net pension expense and related deferred inflows and outflows of resources to AMP on a cost-sharing basis.

Active Miscellaneous Plan members hired prior to January 1, 2013 are required to contribute 7.00% of their annual covered salary and those hired on or after January 1, 2013 are required to contribute 6.75% of their annual covered salary. Alameda's employer contribution rate is determined annually by the actuary 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 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. Alameda is required to contribute the difference between the actuarially determined rate and the contribution rate of employees. The actuarial methods and assumptions used are those adopted by the CalPERS Board of Administration. The employer contribution rates are established, and may be amended, by CalPERS.

The table below sets forth AMP's allocated share of Alameda's city-wide required contributions to the Miscellaneous Plan for the five fiscal years 2016-17 through 2020-21. AMP's estimated allocated share of Alameda's city-wide budgeted contributions to the Miscellaneous Plan for the fiscal year ending June 30, 2022 is $[________]. *{Update}*

	City of Alameda Miscellaneous Plan		
Fiscal Year Ended June 30	**AMP Allocated Share**	**Total City Actuarially Determined Contribution Amount**	**AMP Contributions as a % of Covered Payroll**
2017	$1,631,011	$ 5,273,062	19.60%
2018	1,739,297	5,710,914	20.60
2019	2,105,125	6,968,668	24.45
2020	2,504,271	8,387,122	26.88
2021	2,981,913		31.68

Source: Alameda Municipal Power.

Alameda'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 Alameda's required contributions to CalPERS in future years. Accordingly, Alameda cannot provide any assurances that Alameda's required contributions to CalPERS in future years will not significantly increase (or otherwise vary) from any past or current projected levels of contributions.

On December 21, 2016, the CalPERS Board of Administration voted to lower the pension plan's assumed rate of return for purposes of its actuarial valuations from 7.5% to 7.0% by 2020 (which reduction has been phased in over the period from fiscal year 2017-18 to 2019-20). CalPERS has estimated that with a reduction in the rate of return to 7.0%, most employers could expect a 1% to 3% increase in the percentage of payroll contribution for the normal cost for miscellaneous plans. In addition, CalPERS has estimated that employers could expect gradual increases in their unfunded accrued liability payment, reaching an approximate increase in such payment (relative to the unfunded accrued liability payments projected in the June 30, 2015 valuation report) of 30% to 40% by fiscal year 2024-25 for miscellaneous plans. As a result, required contributions of employers, including Alameda, toward unfunded accrued liabilities, and as a percentage of payroll for normal costs, are expected to increase.

The announcement on July 12, 2021 that CalPERS achieved a preliminary investment return of 21.3% for the period from July 1, 2020 through June 30, 2021 caused the CalPERS Board of Administration to lower CalPERS' discount rate from 7.0% to 6.8% on November 15, 2021 in accordance with a risk mitigation policy that was adopted in 2015, which calls for the discount rate to be lowered if returns exceed the then-current discount rate by two or more percentage points. Lowering the discount rate generally means that employers which contract with CalPERS to administer their pension plans will see increases in their normal costs and unfunded actuarial liabilities.

Effective for the fiscal year ended June 30, 2015, Alameda adopted Governmental Accounting Standards Board ("GASB") Statement No. 68 ("GASB No. 68"), affecting the reporting of pension liabilities for accounting purposes. Under GASB No. 68, Alameda 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 AMP's proportionate share of the Net Pension Liability of Alameda's Miscellaneous Plan as of the June 30, 2016 through June 30, 2020 measurement dates (as reported in Alameda's and AMP's audited financial statements as of the succeeding fiscal year). AMP's proportion of Alameda's net pension liability was based on AMP's fund contributions for the fiscal year relative to the total contributions of the City of Alameda as a whole.

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Alameda Municipal Power
Proportionate Share of the Net Pension Liability – Miscellaneous Plan

Measurement Date[(1)] (June 30)	Proportionate Share of the Net Pension Liability[(2)]	Electric Enterprise Fund Share of the Net Pension Liability[(2)]	Share of Net Position as a % of Share of Total Pension Liability	Share of Net Pension Liability as a % of Its Covered Payroll
2016	29.84%	$21,006,196	72.92%	261.81%
2017	30.19	24,557,226	71.50	295.17
2018	30.26	24,012,403	72.90	284.43
2019	31.99	26,437,127	72.80	307.02
2020	32.00	27,294,740	72.64	292.95

(1) Measured using prior fiscal year annual actuarial valuation rolled forward to measurement date using standard update procedures.

(2) Reflects AMP's share of the City of Alameda's Miscellaneous Plan Net Pension Liability of $70,405,741 as of the June 30, 2016 measurement date, $81,333,405 as of the June 30, 2017 measurement date, $79,349,751 as of the June 30, 2018 measurement date, $82,616,023 as of the June 30, 2019 measurement date, and $_________ as of the June 30, 2020 measurement date, respectively.

Source: Alameda Municipal Power.

In the June 30, 2019 actuarial valuation utilized for measuring the pension liability as of the June 30, 2020 measurement date, the Entry Age Normal Actuarial Cost Method was used. The actuarial valuation assumptions used for determining pension liabilities included (a) a 7.15% investment rate of return (net of administrative expense); (b) projected salary increases ranging from 0.4% to 8.5% depending on age, service and type of employment; (c) an inflation component of 2.50% per year; (d) payroll growth of 2.75]%; and (e) a discount rate of 7.15%.

Retiree Health Benefits. Alameda also provides medical and dental benefits to eligible city employees, including those assigned to AMP, who retire from Alameda, through the City of Alameda Other Post Employment Benefit Plan (the "OPEB Plan"), offered by CalPERS, an agent multi-employer defined benefit healthcare plan. AMP only has miscellaneous employees participating in Alameda's plan.

Alameda contracts with CalPERS to administer its retiree health benefit plan. A menu of benefit provisions as well as other requirements is established by State statute within the Public Employees' Retirement Law. Alameda chooses among the menu of benefit provisions and adopts certain benefit provisions of Alameda City Council resolution. Alameda is responsible for establishing and amending the funding policy of the OPEB Plan.

In order to be eligible for benefits, an employee must retire directly from Alameda under CalPERS. Alameda created an irrevocable trust with Public Agency Retirement Services to fund its retiree health benefits. For eligible miscellaneous employees, Alameda pays the Public Employees' Medical and Hospital Care Act minimum employer contribution on their behalf, which is $143 per month for 2021. These employees receive no other post-employment benefits from Alameda. Contributions to the OPEB Plan for miscellaneous employees are generally based on pay-as-you go financing.

Effective beginning in fiscal year 2017-18, Alameda 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 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.

The table below sets forth certain information regarding AMP's allocated share of Alameda's actuarially determined OPEB contributions for the fiscal years 2017-18 through 2020-21. The amount budgeted for AMP's share of OPEB Plan contributions for fiscal year 2021-22 is $__________.

City of Alameda
OPEB Plan – Miscellaneous Employees

Fiscal Year Ended June 30	Alameda Actually Determined OPEB Contribution	AMP Allocated Share of Alameda Contribution
2018	N/A[(1)]	N/A[(1)]
2019		$77,410
2020		77,410
2021		77,410

[(1)] Alameda established an irrevocable trust in fiscal year 2019; therefore, only three years are shown.
Source: City of Alameda.

Pursuant to GASB No. 75, for the Fiscal Year ended June 30, 2021, AMP reported a net OPEB liability of $1,754,728 for its proportionate share (2.22%) of Alameda's net OPEB liability of $___________ (reflecting a total OPEB liability of $_________ and a fiduciary net position of $__________ for the OPEB Plan). The OPEB Plan Net Position as a percentage of Alameda's total OPEB liability was ____%. The net OPEB liability as a percentage of covered-employee payroll was ___%. The net OPEB liability of the OPEB Plan was measured as of June 30, 2021 and the total OPEB liability for the plan used to calculate the net OPEB liability was determined by an actuarial valuation as of June 30, 2020. AMP's proportion of the City of Alameda's net OPEB liability was based on AMP's Fiscal Year 2019-20 contributions to Alameda's OPEB plan relative to the total contributions of the City as a whole. AMP's proportion of the City of Alameda's total OPEB liability in the June 30, 2020 actuarial valuation was determined using the following actuarial assumptions: (a) a discount rate of 3.09%; (b) payroll growth of 2.75%, plus merit increases; (c) a 2.75% inflation rate; (d) an annual health care cost trend rate of 6.50% initially, declining to 4.50% in 2025 and later years, for PPO plans, and 6.50% initially, declining to 4.50% in 2025 and later years, for HMO plans.

Additional information regarding the City of Alameda's retirement plans and other post-employment benefits can be found in Alameda's annual comprehensive financial reports, which may be obtained at *http://www.cityofalamedaca.gov*.

Insurance

AMP, as a department of the Alameda, participates in Alameda's risk management program. As a member of the California Joint Powers Risk Management Authority ("CJPRMA") and the Local Agency Workers' Compensation Excess Joint Powers Authority ("LAWCX"), Alameda carries both liability and property coverage in excess of self-insurance at varying levels. Through CJPRMA, Alameda carries $40 million in general liability coverage subject to a $500,000 self-insured retention. As a member of CJPRMA, Alameda is a participant in both the vehicle physical damage and property programs. Alameda carries physical damage coverage for vehicles worth $25,000 or more, subject to a $10,000 deductible. With respect to the property and boiler and machinery coverage, Alameda carries "all risk" (excluding flood and earthquake) replacement cost coverage for both real and personal property, subject to a $25,000 deductible. Finally, Alameda carries workers' compensation coverage with statutory limits, in excess of a $350,000 self-insured retention through LAWCX.

Litigation

There is no action, suit or proceeding known to be pending or threatened, restraining or enjoining Alameda in the execution or delivery of, or in any way contesting or affecting the validity of any proceedings of Alameda taken with respect to, the Third Phase Agreement.

Present lawsuits and claims concerning AMP's electric system are incidental to the ordinary course of operations of the electric system and are largely covered by Alameda's self-insurance program. In the opinion of AMP's management and, with respect to such litigation, the Alameda City Attorney, such claims and litigation will not have a materially adverse effect upon the financial position of AMP.

[*City of Alameda Settlement with Securities and Exchange Commission*. As described below, Alameda has entered into a settlement order with the United States Securities and Exchange Commission (the "SEC") pursuant to the SEC's Division of Enforcement's Municipalities Continuing Disclosure Cooperation ("MCDC") Initiative.

In connection with an Offer of Settlement by the City of Alameda dated June 27, 2016, and an Order Instituting Cease-and-Desist Proceedings Pursuant to Section 8A of the Securities Act of 1933, Making Findings, and Imposing Remedial Sanctions and a Cease-and-Desist Order of the United States Securities and Exchange Commission dated August 24, 2016 (the "SEC Order"), the City of Alameda has undertaken to:

(i) Within 180 days of the entry of the SEC Order, establish appropriate written policies and procedures and periodic training regarding continuing disclosure obligations to effect compliance with the federal securities laws, including the designation of an individual or officer at Alameda responsible for ensuring compliance by Alameda with such policies and procedures and responsible for implementing and maintaining a record (including attendance) of such training.

(ii) Within 180 days of the entry of the SEC Order, comply with existing continuing disclosure undertakings, including updating past delinquent filings if Alameda is not currently in compliance with its continuing disclosure obligations.

For good cause shown, the SEC staff may extend any of the procedural dates relating to the Alameda's undertakings. Deadlines for procedural dates are to be counted in calendar days, except that if the last day falls on a weekend or federal holiday, the next business day shall be considered the last day.

(iv) Disclose in a clear and conspicuous fashion the terms of the settlement in any final official statement for an offering by Alameda within five years of the institution of the SEC's proceedings.

(v) Certify, in writing, compliance with the undertakings set forth above. The certification shall identify the undertakings, provide written evidence of compliance in the form of a narrative, and be supported by exhibits sufficient to demonstrate compliance. The SEC staff may make a reasonable request for further evidence of compliance, and Alameda has agreed to provide such evidence. The certification and supporting material shall be submitted to certain specified SEC personnel no later than the one-year anniversary of an institution of the SEC's proceedings.

(vi) Cooperate with any subsequent investigation by the SEC regarding the false statement(s) and/or material omission(s), including the roles of individuals and/or other parties involved.] [Confirm if ok to delete since more than 5 years ago?]

Alameda has established procedures to ensure compliance with its continuing disclosure undertakings in the future for Alameda and for all entities that are created or controlled by Alameda; and has made remedial filings of all delinquent or missing information in its prior undertakings for issues currently outstanding. Alameda fully intends to comply with all other requirements of the SEC Order.

Significant Accounting Policies

AMP's most recent Component Unit Financial Statements for the fiscal year ended June 30, 2021 were audited by Maze & Associates, Pleasant Hill, California, and the Component Unit Financial Statements for the fiscal year ended June 30, 2020 were audited by Eide Bailly, CPAs and Business Advisors, Sacramento, California, in accordance with generally accepted auditing standards. The audited financial statements contain opinions that the financial statements present fairly the financial position of AMP. The reports include certain notes to the financial statements which are not described herein. Such notes constitute an integral part of the audited financial statements. Copies of these reports are available online at *https://www.alamedamp.com/274/Financial-Reports* or upon request from the City of Alameda, Alameda Municipal Power, 2000 Grand Street, Alameda, California 94501 and from their website at *www.AlamedaMP.com*. It is the policy of Alameda to periodically bid, select and retain independent auditors.

Governmental accounting systems are organized and operated on a fund basis. A fund is defined as an independent fiscal and accounting entity with a self-balancing set of accounts recording cash and other financial resources, together with all related liabilities and residual equities or balances, and changes therein. Funds are segregated for the purpose of carrying on specific activities or attaining certain objectives in accordance with special regulations, restrictions or limitations.

AMP's operations are accounted for as an Enterprise Fund. Enterprise funds are used by municipalities to account for operations which are financed and operated similar to private business enterprises, where the intent of the governing body is that the costs and expenses, including depreciation, of providing goods and services to the public on a continuing basis be recovered primarily through user charges.

AMP's accounting records and financial statements are on the accrual basis and are substantially in accordance with the Uniform System of Accounts for Class A and B Electric Utilities prescribed by the FERC, as required by the Alameda City Charter.

Condensed Operating Results and Selected Balance Sheet Information

The following table sets forth summaries of operating results and selected balance sheet information of AMP's electric utility for the five fiscal years 2016-17 through 2020-21. The information for the fiscal years ended June 30, 2017 through June 30, 2021 was prepared by AMP on the basis of its audited financial statements for such years. However, the figures shown and the historical debt service coverage ratios are calculated in accordance with AMP's Electric System Installment Sale Agreement pursuant to which AMP's outstanding electric system revenue obligations were incurred, which may or may not be on the same basis as GAAP, and as such, do not match the line item designations in AMP's audited financial statements.

CITY OF ALAMEDA
ALAMEDA MUNICIPAL POWER
CONDENSED OPERATING RESULTS AND SELECTED BALANCE SHEET INFORMATION

	Fiscal Years Ended June 30				
	2017	**2018**	**2019**	**2020**	**2021**
Electric System Revenues					
Sales of Electricity	$55,925,748	$59,501,406	$61,027,633	$62,731,635	$62,185,866
Other Revenues (1)	3,159,383	1,890,185	1,891,371	1,425,258	2,063,225
REC, LCSF & C&T Sales (6)	5,071,175	3,435,082	4,159,357	2,909,457	2,296,903
Total Electric System Revenues	$64,156,306	$64,827,185	$67,078,361	$67,066,350	$66,545,994
Operation and Maintenance Costs (by FERC categories)					
Purchased Power (2)	$28,201,607	$28,618,484	$29,586,832	$32,246,283	$30,296,114
Energy Efficiency, Solar and Other	1,504,629	1,172,615	1,773,249	1,271,590	1,331,638
Operations & Maintenance	4,674,307	4,814,122	5,033,334	5,055,482	5,524,880
Customer Service, Information Systems	2,170,617	2,296,001	2,617,469	3,179,247	3,177,863
Administrative & General	7,425,117	10,527,575	9,954,555	12,261,784(7)	8,158,825
Customer Relations	530,544	505,711	548,723	587,487	449,614
Jobbing Sales Expense	993,580	367,624	1,242,159	803,802	1,646,595
Balancing Account Adjustment	1,425,636	2,821,087	4,860,258	1,020,615	6,680,252
Total Operation and Maintenance Costs(3)	$46,926,037	$51,123,219	$55,616,579	$56,426,290	$57,265,781
Net Revenues	$17,230,269	$13,703,966	$11,461,782	$10,640,060	$9,280,213
Rate Stabilization Fund Transfers	($5,071,175)	($3,435,082)	($4,159,357)	($2,909,457)	($2,296,903)
Use of Reserves	1,020,393	5,652,517	2,240,289	2,075,437	3,673,585
Adjusted Annual Net Revenues	$13,179,487	$15,921,401	$ 9,542,714	$ 9,806,040	$10,656,895
Debt Service	2,631,044	2,626,368	2,617,703	2,586,594	2,646,470
Debt Service Coverage (4)	5.01	6.06	3.65	3.79	4.03
Amount Available After Debt Service	$10,548,443	$13,295,033	$6,925,011	$7,219,446	$8,010,425
Selected Balance Sheet Information					
Total Unrestricted Cash & Investments(5)	$39,422	$48,058	$56,310	$62,776	$70,496
Rate Stabilization Fund Balance(6)	24,633	21,431	23,399	25,179	23,804
Net Plant in Service	36,275	38,333	35,852	33,186	32,962
Construction Work in Progress	6,452	2,873	3,862	5,198	3,006
Electric Utility Plant-Net	42,727	41,206	39,714	38,384	35,968
Outstanding Electric System Debt	$25,290	$24,070	$22,795	$21,455	$20,045

(1) Other Revenues includes operating and non-operating sources such as solar surcharge, interest income, lease income, account establishment, reconnection and late fees, jobbing sales and other miscellaneous items.
(2) Includes purchased power costs and payments to NCPA and TANC. Also includes prior year budget settlements from NCPA.
(3) Excluding Payments in lieu of taxes and depreciation.
(4) Adjusted Annual Net Revenues divided by debt service.
(5) Includes General Reserve balance held at NCPA. See also “Available Funds” below.
(6) Includes renewable energy credit (REC) sales, low carbon fuel sales (LCSF) and auction sales for cap-and-trade (C&T) placed into reserve for Rate Stabilization Fund. See “– Energy Efficiency and Conservation; Renewable Resources” above.
(7) [ADD FOOTNOTE FOR 2020 A&G EXPENSE INCREASE]

Source: Alameda Municipal Power.

Available Funds. Of the total unrestricted cash and investments, as of June 30, 2021, the balance in cash and cash equivalents available at AMP was $31,120,246 *{confirm}*. In addition, AMP had available in reserve accounts held by NCPA an additional $[5,485,842] as of such date. *{update}*

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CITY OF LODI

Introduction

The City of Lodi ("Lodi") is a general law city in the State of California incorporated in 1906. Lodi is located in the San Joaquin Valley of California, 35 miles south of the State capital of Sacramento, and 90 miles east of San Francisco. Lodi's boundaries encompass approximately 14 square miles.

Lodi provides electric utility service through an electric utility department. The legal responsibilities and powers of the electric utility department, including the establishment of rates and charges, are exercised through the five-member Lodi City Council. Commencing with the November 2018 election, the City has changed to the election of councilmembers by district. Each Councilmember is elected for four years with staggered terms. The Lodi electric utility department is under the direction of the Electric Utility Director who is appointed by the City Manager.

Lodi joined NCPA at its founding in 1968. Lodi participates in several NCPA generation projects and member service programs. In addition, Lodi is an NCPA Pool Member and NCPA's Central Dispatch Center in Roseville provides real-time dispatching and scheduling of most available resources to serve Lodi's electric load.

The Lodi electric system serves the entire area of the City of Lodi (approximately 14 square miles) and has approximately 117 miles of overhead lines and approximately 139 miles of underground lines. During the fiscal year ended June 30, 2021, the Lodi electric system served 27,485 customers, comprised of 24,139 residential customers, 3,148 commercial/industrial customers and 166 other customers. In 2006, according to Lodi SCADA system records, an all-time, historical high peak demand of 141.7 MW was reached.

Only the revenues of the Lodi electric system will be available to pay amounts owed by Lodi under the Third Phase Agreement.

The Lodi electric department's main office is located at 1331 South Ham Lane, Lodi, California 95242, (209) 333-6762. For more information about Lodi and its electric system, contact Jeff Berkheimer, Electric Utility Director, at the above address and telephone number. A copy of the most recent annual comprehensive financial report of the City of Lodi (the "ACFR" or "Annual Report") is available on Lodi's website at *http://www.lodi.gov* and on the Municipal Securities Rulemaking Board's Electronic Municipal Market Access system at *http://emma.msrb.org/*. The Annual Report is incorporated herein by this reference. However, the information presented on such website or referenced therein other than the Annual Report is not part of this Official Statement and is not incorporated by reference herein.

Power Supply Resources

The following table sets forth information concerning Lodi's power supply resources and the energy supplied by each during the fiscal year ended June 30, 2021.

CITY OF LODI
ELECTRIC UTILITY DEPARTMENT
POWER SUPPLY RESOURCES
For the Fiscal Year Ended June 30, 2021

Source	Capacity Available (MW)[1]	Actual Energy (MWh)	% of Total Energy
Purchased Power[2]:			
Western Area Power Administration	7.1	15,174	3.3%
NCPA			
Geothermal Project	11.5	78,057	17.2
Hydroelectric Project	26.2	21,966	4.8
Combustion Turbine Project No. 1	9.5	1,589	0.3
Capital Facilities, Unit One	19.6	17,648	3.9
Lodi Energy Center	28.7	116,996	25.7
Contracts and Exchanges[3]	59.9	203,299	44.7
Total	162.5	454,729	100.0%
Total Capacity and Energy Sold at Wholesale	N/A	4,636	
Lodi System Requirement for Retail Load[4]	132.5	450,093	

(1) Information compiled from NCPA Annual Resource Adequacy Filings.
(2) Entitlements, firm allocations and contracts.
(3) Includes purchases and contracts secured through NCPA for Lodi.
(4) Information compiled from NCPA All Resources Bill. Includes supply from line losses.
Source: City of Lodi.

In the fiscal year ended June 30, 2021, Lodi's average cost of power delivered to the Lodi electric system was 9.4 cents per kWh.

Purchased Power

Western. Lodi is a party to the Contract for Electric Service Base Resource (the "Base Resource Contract") with the Western Area Power Administration ("Western"), under which Lodi takes delivery of a 0.569% share of the base resource output of the Central Valley Project ("CVP"). The CVP consists of a series of federal hydroelectric facilities located and interconnected in Northern California. The amount of energy delivered to Lodi under the Base Resource Contract is subject to hydrology variability and water storage levels within the CVP. The Base Resource Contract is structured on a take-or-pay basis; whereby Lodi is obligated to pay its share of Western's costs whether or not it receives any power. Energy under the Base Resource Contract is scheduled for delivery to Lodi by NCPA. Service under the Base Resource Contract is scheduled to expire on December 31, 2024. Pursuant to its 2025 power marketing plan, Western has made available new 30-year contracts for up to 98% of a customer's existing base resource allocation. Under the 2025 power marketing plan, Western will allow an existing customer to reduce its base resource percentage allocation with at least six month's written notice to Western prior to January 1, 2025. Lodi executed Base Resource Contract 20-SNR-02347, dated January 28, 2021, which provides Lodi with 0.55792% of Western's Base Resource effective January 1, 2025. The term of the new Base Resource Contract extends to December 31, 2054. Lodi may reduce its Base Resource percentage or terminate this Base Resource Contract for any reason through June 30, 2024.

Other Purchases. Power purchases for fiscal year 2020-21, as reflected in the Contracts and Exchanges figures listed in the table above, are associated with short-term purchases and the Astoria 2 Solar Project. NCPA transacts and schedules daily and hourly (spot) power purchases and sales to balance and serve Lodi's native load requirements.

Joint Powers Agency Resources

NCPA. Lodi does not independently own any generation assets but, in addition to power purchased from Western and others, Lodi is a participant in various NCPA projects. Lodi has a 10.37% project participation entitlement share of the NCPA Hydroelectric Project; a 39.5% project participation entitlement share of the NCPA Capital Facilities (also referred to as the Combustion Turbine Project Number Two); a 14.56% project participation entitlement share of the Geothermal Generating Unit 2 Project and a 6.0% project participation entitlement share of the Geothermal Generating Project Number 3 (which are jointly operated as a single project, the NCPA Geothermal Project); a 13.39% project participation entitlement share in the NCPA Combustion Turbine Project Number One (exclusive of the portion acquired by the City of Roseville); and a 9.5% generation entitlement share in NCPA's Lodi Energy Center Project. Lodi additionally participates in the NCPA Geysers Transmission Project, in which it has a 20.61% entitlement share, pursuant to which NCPA, on behalf of Lodi, delivers output from the geothermal generating assets pursuant to the agreement of co-tenancy in the Castle Rock Junction-Lakeville 230-kV Transmission Line. For a description of such resources, see "THE HYDROELECTRIC PROJECT" and "OTHER NCPA PROJECTS" in the front part of this Official Statement. For each of these NCPA projects in which Lodi participates, Lodi is obligated pursuant to contract, to pay, on an unconditional take-or-pay basis, as an operation and maintenance cost of its electric system, its entitlement share of the debt service on NCPA bonds issued for the projects, as well as its share of all operation and maintenance expenses of the projects. See also "– Indebtedness; Joint Powers Agency Obligations" below.

TANC California-Oregon Transmission Project. Lodi is a member of the Transmission Agency of Northern California ("TANC") and has executed an agreement (the "TANC Agreement") to acquire a participation percentage share of TANC's entitlement of the California-Oregon Transmission Project ("COTP") transfer capability. Lodi participated in the acquisition of an increased share of transfer capability of the COTP in connection with the acquisition by TANC in April 2008 of the COTP transmission assets of the City of Vernon, California ("Vernon"), one of the original owners of the COTP, which acquisition was financed by TANC through the issuance of additional TANC debt (the "Vernon acquisition debt"). Lodi has a participation share of 26.7 MW of TANC's entitlement to transfer capability of the COTP and is responsible for 1.92% of TANC's COTP operating and maintenance expenses and 1.89% of TANC's COTP debt service (non-Vernon) and 2.62% of the Vernon acquisition debt. See "CITY OF ALAMEDA – Transmission Resources – *TANC California-Oregon Transmission Project*" for a further description of the COTP and the TANC Agreement.

On April 2, 2014, the Lodi City Council approved a 25-year layoff of Lodi's 26.7 MW share of COTP transfer capability, effective July 1, 2014, whereby Lodi and all of the TANC Members who are in the balancing authority area of the CAISO laid off their interests to certain other COTP participants (*i.e.*, Modesto Irrigation District ("MID"), Turlock Irrigation District ("TID") and Sacramento Municipal Utility District ("SMUD")) (subject to certain rights of Lodi and the other layoff entities to recall, and certain rights of MID, TID, and/or SMUD to return, up to 50% of their respective shares of the entitlement amount laid off). In exchange for their respective increased right to use of COTP transfer capability, MID, TID and SMUD will pay Lodi's (and the other layoff entities') current allocated share of COTP costs. This layoff arrangement does not change Lodi's membership status in TANC and does not relieve Lodi of its obligations under the TANC Agreement in the event of any default in payment by an acquiring party. See also "– Indebtedness; Joint Powers Agency Obligations" below.

TANC Tesla–Midway Transmission Service. TANC and certain TANC Members have arranged for Pacific Gas & Electric Company ("PG&E") to provide TANC and its members with 300 MW of firm bi-directional transmission capacity on its transmission system between its Midway Substation near Buttonwillow, California, and its Tesla Substation near Tracy, California, near the southern physical terminus of the COTP (the "Tesla–Midway Transmission Service") under an agreement known as the South of Tesla Principles. Lodi's share of this Tesla–Midway Transmission Service is 6.21 MW. Lodi has utilized its full allocation of Tesla–Midway Transmission Service for firm and non-firm power transactions in the past. See "CITY OF SANTA CLARA – Transmission Resources – *TANC California-Oregon Transmission Project*" for a further description of the COTP and the TANC Agreement.

Renewable Resources

General; RPS Compliance. Lodi expects to procure, either on its own or through NCPA, a renewable power resource portfolio that satisfies applicable State requirements, the main provisions of which are currently contained in the California Renewable Energy Resources Act ("SBX1-2") enacted in 2011, the Clean Energy and Pollution Reduction Act of 2015 ("SB 350") and the 100 Percent Clean Energy Act of 2018 ("SB 100"). See "CERTAIN FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY – State Legislation and Regulatory Proceedings" in the front part of this Official Statement.

Lodi's power mix in calendar years 2020 and 2019 consisted of 27.4% and 30.5% of eligible renewable resources, respectively. Pursuant to SBX1-2, during Compliance Period 1 (January 1, 2011 through December 31, 2013), an average of 20% of the electric system's retail sales were required to be procured from eligible renewable energy resources. Lodi exceeded the RPS target under SBX1-2 for Compliance Period 1, with an average of approximately 21.7% of Lodi's energy portfolio supplied from renewable resources over such period. During Compliance Period 2 (January 1, 2014 through December 31, 2016) under SBX1-2, the electric system was required to procure electricity products from eligible renewable energy resources representing a total equal to 20% of 2014 retail sales, 20% of 2015 retail sales and 25% of 2016 retail sales. Lodi exceeded the RPS target for Compliance Period 2, with approximately 21.1% of the City's energy portfolio supplied from renewable resources in calendar year 2014, approximately 21% of Lodi's energy portfolio supplied from eligible renewable resources in calendar 2015, and approximately 24% of Lodi's energy portfolio supplied from eligible renewable resources in calendar year 2016. During Compliance Period 3 (January 1, 2017 through December 31, 2020) under SBX1-2, the electric system was required to procure electricity products from eligible renewable energy resources representing a total equal to 27% of 2017 retail sales, 29% of 2018 retail sales, 31% of 2019 retail sales, and 33% of 2020 retail sales. Lodi also exceeded the RPS target for Compliance Period 3, with approximately 31.1% of the City's energy portfolio supplied from eligible renewable resources in calendar year 2017, approximately 34.6% in 2018, approximately 30.5% in 2019 and approximately 27.4% of Lodi's energy portfolio supplied from eligible renewable resources in calendar year 2020. With its existing power resources, including participation in recently operational renewable energy projects (described below), and historic carryover, Lodi anticipates meeting its Renewable Portfolio Standard ("RPS") requirements through 2024.

In addition to geothermal and small hydroelectric resources through NCPA, Lodi's current renewable power resources include additional solar and hydroelectric resources, which are described below.

Astoria 2 Solar. The Astoria 2 Solar Project, which reached commercial operation on December 9, 2016, is a 75 MW photovoltaic plant developed by Recurrent Energy, located in the southeastern portion of Kern County. Lodi entered into a power purchase agreement with Recurrent Energy for a 13.3333%, or 10 MW, share of the output of the Astoria 2 Solar Project, which is enough energy to meet approximately 7% of Lodi's retail load. The contract term for the Astoria 2 Solar Project is 20 years. Energy from this project qualifies as Portfolio Content Category 1 energy under RPS. Combined with existing generation resources and historic carryover, this project will enable Lodi to meet its RPS obligations through 2024.

The cost of power from the Astoria 2 Solar Project is fixed at \$63/MWh for the 20-year life of the project. The price is only paid for energy actually delivered. Lodi does not have any ownership interest in the project and will not incur any capital expenditures related to the project.

Antelope Expansion Solar. The Antelope Expansion Phase 1 Solar Facility ("Antelope Expansion Project"), is a 51 MW photovoltaic plant being developed by Antelope Expansion 1B, LLC, located in the City of Lancaster, Los Angeles County, California. The Antelope Expansion Project is expected to reach commercial operation by April 2022. NCPA, on behalf of Lodi and other NCPA members, entered into a power purchase agreement with Antelope Expansion 1B, LLC for a 33.78%, or 17 MW, share of the output of the Antelope Expansion Project. Lodi has a 58.82%, or 10 MW, project participation percentage share of the Antelope Expansion Project. The contract term for the Antelope Expansion Project is 20 years. Energy from this project will qualify as Portfolio Content Category 1 energy for RPS compliance purposes. The output produced from the project will contribute to Lodi's compliance with RPS obligations in the current and future compliance periods.

The cost of power from the Antelope Expansion Project is fixed at \$39.00/MWh for the 20-year life of the project. The price is only paid for energy actually delivered. Lodi does not currently have any ownership interest in the project, and as such will not incur any capital expenditures related to the project.

South Feather River Hydroelectric. The South Feather Power Project (the "SFPP") is a 121.5 MW hydroelectric project, consisting of four powerhouses located in Butte and Yuba counties, and is owned and operated by South Feather Water and Power Agency ("SFWPA"). On December 6, 2021, NCPA, on behalf of Lodi and other NCPA members, entered into a power purchase agreement with SFWPA to purchase all project output produced by the SFPP. Lodi has an 8.23%, or 10 MW, project participation percentage share of the project. The contract term consists of an initial 10 year term, with an option to extend the contract for a full 20 year term. Energy generated from powerhouses with a capacity less than 30 MW will qualify as Portfolio Content Category 1 energy for RPS compliance purposes. Approximately 20% of the output produced from the project will contribute to Lodi's compliance with RPS obligations beyond the 2022 compliance period. Combined with existing generation resources and historic carryover, this project will enable Lodi to meet its RPS obligations through mid-2025.

The cost of power from the SFWPA Project is fixed at \$35.00/MWh for the energy Base Output of 191,192 MWh annually. During each full contract year, the cost of the energy Variable Output that exceeds the energy Base Output is fixed at \$33.98/MWh. The Resource Adequacy ("RA") capacity is paid based on its qualified monthly Net Qualifying Capacity (NQC), and the monthly RA capacity value is paid at a fixed rate of \$6.25 per kW-month. Lodi does not currently have any ownership interest in the project, and as such will not incur any capital expenditures related to the project.

Future Power Supply Resources

Based upon its current forecasted sales growth, resource mix and market prices, Lodi expects its annual balance-of-month, day-ahead, and hour-ahead purchases will on average be less than 25% of total energy requirements over the next two years. Lodi's interest in multiple NCPA generation projects provides substantial capacity toward covering Lodi's net short position in the event that market prices rise above the respective unit's cost of production. Lodi has developed medium-term hedging strategies to reduce volatility associated with market purchases and the seasonal nature of its loads and resources. In addition, due to the long lead time in acquiring certain resources, including renewable resources, Lodi, through

NCPA, is pursuing, and will continue to consider, additional projects that may be included in its future resource mix in coordination with NCPA and other NCPA members.

Energy Efficiency and Conservation

Since 1998, Lodi has implemented a public benefits program as required by State law, a component of which is demand-side management (commonly referred to as energy efficiency and conservation). Under this program, Lodi offers customers the opportunity to invest in energy efficiency products through rebates and information to help make the best choices for home and business. For the home, instant savings can be achieved for heating and cooling appliances, induction cooktops and ranges, web-enabled thermostats, energy efficient windows, weatherization and more. For business and industrial settings, Lodi provides an array of common rebates for LED lighting, refrigeration, HVAC, heat pumps, and commercial food service equipment. Customized energy efficiency solutions which begin with site visits and a detailed analysis of how electric power is used by business and how it can be managed is also available. Customized solutions can be identified throughout many business sectors ranging from food processing to healthcare, and from manufacturing to warehousing.

Lodi also continues to provide energy education for residential and non-residential customers, including on-site energy audits, and hosts a number of programs to promote energy education and customer outreach. As part of its education and customer outreach efforts, Lodi provides a school-based energy efficiency education program, offers free energy efficiency measures through its direct install program and occasionally sponsors STEM focused events. Lodi provides low-income and disadvantaged persons and families with emergency energy assistance credits on utility bills with limitations, and utility bill discounts which are based on an income-eligibility process.

Lodi utility customers continue to be positively impacted by one or more of Lodi's public benefits programs, either in the form of a direct utility rebate or via one of its outreach and educational programs.

Interconnections, Transmission and Distribution Facilities

Lodi's electric system is interconnected with the system of PG&E via three 60 kV lines. Lodi owns facilities for the distribution of electric power within the city limits of Lodi, which includes approximately 14 miles of 60 kV power lines, approximately 256 miles of 12 kV distribution lines (approximately 54% of which are underground) and four substations. During calendar year 2021, Lodi's system index of average duration of interruption (SAIDI) was 20.5 minutes per customer.

Wildfire Risks

Lodi does not own or operate any transmission assets, and the service area of the Lodi electric system is not located in a designated wildfire area. In connection with the operation of its facilities and equipment, Lodi currently has in place a number of safety and emergency response measures. Lodi conducts a visual inspection of its distribution system each year. Lodi also performs ongoing vegetation management activities, including both preventive measures to control vegetation growth and actions to address reports of potentially hazardous conditions. Through its SCADA operations and control system, Lodi has the ability to remotely operate equipment on its system as needed. Lodi maintains an Electric Emergency Plan to establish response protocols in the event of an emergency, including fire. The Electric Emergency Plan is reviewed and updated annually. On November 20, 2019, the Lodi City Council approved Lodi's Wildfire Mitigation Plan. Pursuant to the requirements of California Senate Bill 901 and Assembly Bill 1054, Lodi has also completed its third party independent evaluation. The Lodi City Council most recently approved Lodi's annual update to its Wildfire Mitigation Plan on December 1, 2021.

See also "CERTAIN FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY – State Legislation and Regulatory Proceedings – *Legislation Relating to Wildfires; Related Risks*" in the front part of this Official Statement.

COVID-19

The spread of the novel strain of coronavirus (and variants thereof) and the disease it causes (now known as "COVID-19") has had significant negative impacts throughout the world, including in California. In 2020, the World Health Organization declared the COVID-19 outbreak to be a pandemic, and states of emergency have been declared by the United States, the State and numerous counties throughout the State. The purpose behind these declarations was to coordinate and formalize emergency actions across federal, state and local governmental agencies, and to proactively prepare for a wider spread of the virus.

On March 19, 2020, in an effort to slow the spread of COVID-19, Governor Newsom issued Executive Order N-33-20 ordering individuals living in the State to stay home or at their place of residence except for specified exceptions, including exceptions for certain sectors of the workforce that were classified as providing essential services and products, which allowed businesses and workers in such sectors to continue to operate on-site operations while Executive Order N-33-20 was effective. On June 11, 2021, Governor Newsom issued two executive orders, which became effective on June 15, 2021, which had the effect of rescinding a majority of the COVID-19-related restrictions and providing a timeline for gradually lifting certain of the other restrictions that were not fully rescinded on June 15, 2021.

During the pandemic, Lodi has experienced a decline in electricity demand by the commercial sector while electricity usage by the residential sector increased, as might be expected with many retail establishments being closed and people staying home. Lodi also experienced an increase in demand on the industrial side with one of its largest customers continuing to expand and build upon its manufacturing of medical testing protocols. See "Customers, Energy Sales, Revenues and Demand."

Historically, Lodi's annual write-offs for uncollectible accounts have been less than 1% of gross billings of the Electric System. Since the onset of the COVID-19 pandemic, write-offs for uncollectible accounts has increased to approximately 11% of gross billings for Fiscal Year 2020-21. To help mitigate the economic impact of COVID-19 and the related governmental regulations on its customers, Lodi implemented a payment deferral program for all customers of Lodi utilities, which included the suspension of the disconnection of services by City utilities for non-payment of utility bills for a period beginning in March 2020 and extending through May 2022. Customers were not charged late fees and were not shut off for non-payment during this period. Additionally, each customer received a locally funded utility bill credit in May 2020, the amount of which varied based on customer class.

Lodi was allocated approximately $1 million under the California Department of Community Services and Development California Arrearage Payment Program ("CAPP"), to aid the accounts that have fallen behind during the period of May 4, 2020 through June 15, 2021, which in turn is expected by Lodi to lower the uncollectible revenue amount. In addition, $1.5 million in funds was allocated from the American Rescue Plan Act which were used if a customer demonstrated that they earned less in 2020 than 2019. CAPP funds will pay the entirety of electric charges for active residential accounts, and will provide recovery of approximately 60% of outstanding electric charges for closed accounts.

With widespread vaccination currently underway in the United States and many countries worldwide, governmental-imposed stay-at-home orders and restrictions on operations of schools and businesses implemented to respond to and control the outbreak have been eased or eliminated. However, restrictions may be re-imposed in various jurisdictions from time to time as local conditions warrant. Lodi cannot predict whether any reinstatement or expansion of stay-at-home orders and travel or other restrictions will occur or when a full resumption of all economic activity will be achieved. The ultimate impact of COVID-19 on the operations and finances of Lodi or the Electric System is unknown and there can be no assurances that COVID-19 will not materially adversely impact the financial condition of Lodi or the Electric System in the future. There are many variables that will continue to contribute to the economic impact of the COVID-19 pandemic and the recovery therefrom, including the length of time social distancing measures are in place, the effectiveness of State and federal government relief programs and the timing for containment and treatment, new coronavirus strains, vaccinations efforts and vaccine hesitancy. Lodi cannot predict the extent or duration of such impacts.

Rates and Charges

Lodi has the exclusive jurisdiction to set electric rates within its service area. These rates are not subject to review by any State or federal agency.

Lodi's fiscal year 2020-21 average rate per kWh for residential service was 19.2 cents. Lodi's fiscal year 2020-21 average rate for commercial and industrial service was 15.4 cents per kWh. Lodi's fiscal year 2021-22 average rate per kWh for residential service is projected to be 19.6 cents. Lodi's fiscal year 2021-22 average rate for commercial and industrial service is projected to be 16.3 cents per kWh.

The following table presents a recent history of Lodi's rate increases since 2013. The last base rate increase took effect July 1, 2017.

CITY OF LODI
ELECTRIC UTILITY DEPARTMENT
RATE CHANGES

Effective Date	Percent Change
January 2022	Update to Economic Development rates
December 2021	NEW LED Dusk to Dawn rate tariff
December 2018	Update to Economic Development rates
July 2018	Revision of Power Factor charge for non-residential customers
December 2017	Elimination of Solar Surcharge
September 2017	NEW Energy Purchase rate tariff (NEM 2.0)
July 2017	Average 2% increase across all rate classes Electric Vehicle rate restructure replacing minimum charge with customer charge and aligning energy charges with residential rates; City rate restructure replacing minimum charge with customer charge
November 2016	Residential rate restructure replacing minimum charge with customer charge and reduction to 3 energy tiers; Mobile home park rate restructure replacing minimum charge with customer charge, reducing pad discount and reduction to 3 energy tiers
September 2015	Extended Economic Development rates
January 2015	Average 5% increase across all rate classes
July 2013	Established Electric Vehicle and Industrial Equipment Charging Rates

Source: City of Lodi.

The Lodi City Council reviews electric system rates periodically and makes adjustments as necessary. All customers pay rates in accordance with the standard rate tariffs published in the Lodi Municipal Code.

Lodi implemented an Energy Cost Adjustment ("ECA") in August 2007. The purpose of the ECA is to recover market power costs due to the fluctuations in power market conditions and energy sales. The ECA is reviewed monthly and is either increased or decreased as market conditions and energy sales change. The historic, average ECA is listed below.

CITY OF LODI
AVERAGE ENERGY COST ADJUSTMENT
For Fiscal Years 2016-17 through 2020-21

Fiscal Year	ECA ($/kWh)
2016-17	0.0056
2017-18	0.0123
2018-19	0.0103
2019-20	0.0190
2020-21	0.0143

Largest Customers

The ten largest customers of Lodi's electric system in terms of kWh sales, as of June 30, 2021, accounted for 25% of total kWh sales and 19% of revenues. While the City of Lodi as a customer is the largest customer of the electric utility in terms of total kWh sales (4.5%) and total revenues (3.1%), the second largest customer accounted for 3.8% of total kWh sales and 2.6% of total revenues.

Customers, Sales, Revenues and Demand

The number of customers, kWh sales, revenues derived from sales by classification of service and peak demand during the five fiscal years 2016-17 through 2020-21, are listed below.

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CITY OF LODI
ELECTRIC UTILITY DEPARTMENT
CUSTOMERS, SALES, REVENUES AND DEMAND[1]

	Fiscal Years Ended June 30,				
	2017	**2018**	**2019**	**2020**	**2021**
Number of Customers:					
Residential	22,870	23,145	23,480	23,673	24,139
Commercial	3,071	3,075	3,104	3,139	3,148
Industrial	41	41	41	32	32
Other	170	169	173	163	166
Total	26,152	26,430	26,798	27,007	27,485
Kilowatt Hour (kWh) Sales:					
Residential	146,192,111	155,539,509	147,116,802	157,421,444	169,807,599
Commercial	149,882,241	144,244,913	148,133,314	145,157,686	143,702,611
Industrial	118,900,040	115,066,917	104,931,881	103,855,769	114,249,333
Other	10,436,182	10,306,535	10,384,817	10,568,612	11,324,178
Total	425,410,574	425,157,874	410,566,814	417,003,511	439,083,721
Revenues from Sale of Energy[2]					
Residential	$26,021,916	$27,967,919	$27,702,390	$30,390,732	$32,664,848
Commercial	24,432,075	25,105,915	25,081,515	26,070,270	25,308,745
Industrial	13,852,860	14,877,597	13,908,500	14,356,871	14,810,368
Other	1,540,730	1,295,279	1,268,949	1,363,743	1,413,273
Total	$65,847,581	$69,246,709	$67,961,354	$72,181,616	$74,197,234
Peak Demand (MW)	128.7	130.9	117.9	125.9	132.5

(1) Columns may not add to totals due to rounding.
(2) Excludes revenues from California Energy Commission Tax.
Sources: City of Lodi Customer Information System reports.

Service Area

Population. Lodi is located in the San Joaquin Valley, adjacent to State Highway 99, between the City of Stockton, 10 miles to the south, and the City of Sacramento, 35 miles to the north. The service area of Lodi's electric system is coterminous with the city boundaries. The local economy is diverse among residential, agricultural, commercial and industrial sectors.

The following chart indicates the growth in the population of the City of Lodi, the County of San Joaquin and the State of California since 1970.

**CITY OF LODI, COUNTY OF SAN JOAQUIN,
STATE OF CALIFORNIA POPULATION ESTIMATES
(1970–2010 as of April 1; 2011-2021 as of January 1)**

Year	City of Lodi	County of San Joaquin	State of California
1970	28,691	291,073	19,971,069
1980	35,221	347,342	23,667,764
1990	51,874	480,628	29,760,021
2000	56,999	563,598	33,871,653
2010	62,134	685,306	37,253,956
2011	62,591	692,211	37,561,624
2012	63,068	699,127	37,924,661
2013	63,459	704,615	38,269,864
2014	63,623	711,119	38,556,731
2015	64,376	722,580	38,865,532
2016	64,952	733,728	39,103,587
2017	65,606	744,843	39,352,398
2018	66,389	752,985	39,519,535
2019	67,430	764,373	39,605,361
2020	68,011	773,505	39,648,938
2021	68,751	783,534	39,466,855

Source: 1970-2010, as of April 1, based on historical U.S. Census population data compiled by the California State Department of Finance. 2011-2021, as of January 1, State of California, Department of Finance, E-4 Population Estimates for Cities, Counties and the State, with 2010 Census Benchmark. Sacramento, California, May 2021.

Employment. Lodi is a worldwide agricultural shipping center for the San Joaquin Valley. The surrounding prime agricultural land is a major producer of wine grapes.

The City's employment base is diverse with industry that includes agribusiness, biotechnology, distribution, food and beverage product manufacturing, general service, government, health care, heavy manufacturing, and wine-based tourism and lodging.

The largest employers in Lodi as of June 30, 2021 are as follows:

CITY OF LODI LARGEST EMPLOYERS

Employer	Number of Employees
Lodi Unified School District	1,389
Pacific Coast Producers	1,298
Adventist Health Lodi Memorial[(1)]	1,204
Blue Shield of California	1,042
Walmart Supercenter	439
City of Lodi	415
Rich Products fka Cottage Bakery	276
Costco Wholesale	265
Frank C Alegre Trucking Inc.	210
Farmers & Merchant Bank	191

(1) Count includes full-time, part-time, temporary and seasonal employees.
Source: MuniServices, LLC / *an Avenu Insights & Analytics Company*
Results based on direct correspondence with city and local businesses.

The following table sets forth certain information regarding employment in the City of Lodi, the County of San Joaquin and the State from 2016 through 2020.

CITY OF LODI
UNEMPLOYMENT RATES 2016 TO 2020[(1)]

Year	City of Lodi	County of San Joaquin	State of California
2016	8.0%	8.1%	5.5%
2017	6.7	7.0	4.8
2018	5.9	6.1	4.3
2019	5.7	5.9	4.2
2020	8.0	8.1	10.1

(1) Unemployment rates not seasonally adjusted, average annual rates.

Source: State of California Employment Development Department, Labor Market Information Division, Monthly Labor Force Data for Cities and Census Designated Places, Annual Averages – Revised.

Assessed Valuation. A five-year history of assessed valuations in Lodi is as follows:

CITY OF LODI
ASSESSED VALUATIONS
For Fiscal Years 2016-17 through 2020-21
(Dollar Amounts in Thousands)

Fiscal Year	Land	Improvements	Personal Property	Total	Less Exemptions	Net Assessed Value
2016-17	$1,711,208	$3,854,604	$294,457	$5,860,269	$334,485	$5,525,784
2017-18	1,812,408	4,042,264	317,727	6,172,399	339,542	5,832,857
2018-19	1,873,216	4,286,480	275,440	6,435,136	345,178	6,089,958
2019-20	1,971,712	4,614,260	229,720	6,815,692	338,170	6,477,522
2020-21	2,077,223	4,894,256	224,670	7,196,149	353,561	6,842,588

Source: San Joaquin County Auditor-Controller's Office.

Forecast of Capital Expenditures

Lodi's five-year capital projection for electric facilities contemplates potential capital expenditures for substation upgrades, streetlight improvements, ongoing overhead and underground maintenance, and related system reliability projects. As reflected in the five-year capital improvement program forecast prepared in connection with the City of Lodi fiscal year 2021-22 budget, which was approved by the City Council on June 2, 2021 and is adjusted from time to time based on priorities and spending, capital expenditures for the electric utility system over the next five years (not including the project described in the next paragraph) are estimated to cost approximately $21 million. Lodi anticipates funding such capital costs from rate revenues and special development fees.

In addition to such capital expenditures as described above, approved in March 2018 by the CAISO, the Northern San Joaquin 230 kV Transmission Project will help address the area's reliability and capacity needs. The project includes connecting PG&E's existing Brighton-Bellota 230 kV Transmission Line into PG&E's Lockeford Substation and building a new 230 kV double circuit transmission line from PG&E's Lockeford Substation to a new PG&E 230 kV switching station in Lodi. Lodi's 230/60kV Substation Project consists of two 230/60kV transformers along with site improvements, facilities and equipment required for the interconnection to PG&E's new 230 kV switching station and to Lodi's existing 60/12kV

Industrial Substation. PG&E has indicated that the expected commercial operation date of the Northern San Joaquin 230 kV Transmission Project is in the fourth quarter of 2027. The cost to Lodi is currently estimated to be approximately $30 million, which Lodi expects to be funded by electric system revenue debt financing. The project is anticipated to realize a cost savings of approximately $6 million annually by eliminating the low voltage transmission access charge.

Indebtedness; Joint Powers Agency Obligations

As of January 31, 2022, Lodi had outstanding $35.3 million principal amount of obligations payable from net revenues of Lodi's electric utility system. These obligations are subordinate to the payments required to be made with respect to the Lodi's obligations to NCPA and TANC described below. In addition, Lodi has an outstanding loan with F&M Bank in the amount of $229,405 associated with an LED Streetlight Improvement Project. The annual loan payments are paid from Greenhouse Gas Free Allowance proceeds. Lodi has no variable rate or auction rate direct debt.

As previously discussed, Lodi participates in certain joint powers agencies, including NCPA and TANC, which have issued indebtedness to finance the costs of certain projects on behalf of the respective project participants. Obligations of Lodi under its agreements with respect to TANC and NCPA constitute operating expenses of Lodi. Such agreements 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. Certain of these agreements contain "step up" provisions obligating Lodi to pay a share of the obligations of a defaulting participant. Lodi's participation and share of debt service obligation (without giving effect to any "step up" provisions) for each of such joint powers agency projects in which it participates are shown in the following table.

CITY OF LODI
ELECTRIC UTILITY DEPARTMENT
OUTSTANDING DEBT OF JOINT POWERS AGENCIES
(Dollar Amounts in Millions)
(As of January 31, 2022)

	Outstanding Debt(1)	Lodi's Participation(2)	Lodi's Share of Outstanding Debt(1)
NCPA			
Geothermal Project Three	$ 10.8	10.28%	$ 1.1
Hydroelectric Project	223.3	10.37(3)	23.8(3)
Capital Facilities Project	13.8	39.50	5.5
Lodi Energy Center, Issue One	206.9	17.03	35.2
TANC			
South of Tesla	2.5	2.07(4)	0.1(4)
TOTAL	$457.3		$65.7

(1) Source: NCPA. Outstanding debt does not include unamortized premium/discount.
(2) Participation obligation is subject to increase upon default of another participant. Such increase shall not exceed, without the written consent of a non-defaulting participant, an accumulated maximum of 25% of such non-defaulting participant's original participation.
(3) Lodi's actual payments represent approximately 10.64% of outstanding debt service as a result of credit to non-participating members with respect to portion of debt obligation.
(4) Obligation shown represents portion of TANC COTP debt allocated to Tesla-Midway Transmission Service. Excludes Lodi's 1.92% participation share of TANC COTP entitlement which has been assigned to other TANC members. Lodi remains contractually obligated for its share to the extent not paid by the assignees. See "– Joint Powers Agency Resources – *TANC California-Oregon Transmission Project*."

Lodi estimates its payment obligations for debt service on its joint powers agency debt obligations aggregated approximately $8.8 million for the fiscal year ended June 30, 2021 and will aggregate approximately $8.9 million for the fiscal year ending June 30, 2022. It should be noted that these amounts do not include any COTP amount as Lodi's share of the debt was laid off effective July 1, 2014. A portion of the joint powers agency debt obligations are variable rate debt, liquidity support for which is provided through liquidity arrangements with banks. Unreimbursed draws under liquidity arrangements supporting joint powers agency variable rate debt obligations bear interest at a maximum rate substantially in excess of the current interest rates on such obligations. Moreover, in certain circumstances, the failure to reimburse draws on the liquidity agreements may result in the acceleration of scheduled payment of the principal of such variable rate joint powers agency obligations. To the extent a joint powers agency has entered into interest rate swap agreements for the purposes of substantially fixing the interest cost with respect to variable rate joint powers agency obligations, there is no guarantee that the floating rate payable to such joint powers agency pursuant to such interest rate swap agreements will match the variable interest rate on the associated variable rate joint powers agency debt obligations to which the respective interest rate swap agreement relates at all times or at any time. Under certain circumstances, the swap provider may be obligated to make payments to the joint powers agency under their respective interest rate swap agreement that is less than the interest due on the associated variable rate joint powers agency debt obligations to which such interest rate swap agreement relates. In such event, such insufficiency will be payable from the obligated joint powers agency members (a corresponding amount of which proportionate to its debt service obligations to such joint powers agency could be due from Lodi). In addition, under certain circumstances, each of the swap agreements is subject to early termination, in which event the joint powers agency could be obligated to make a termination payment to the applicable swap provider (a corresponding amount of which proportionate to its debt service obligations to such joint powers agency could be due from Lodi). The only currently outstanding interest rate swap agreement related to Lodi's variable rate joint powers agency debt obligations is the 2008 Series A Hydroelectric Swap which is expected to be terminated in connection with the issuance of the 2022 Bonds. See "PLAN OF REFUNDING" in the front part of this Official Statement.

Employees

Labor Relations. As of June 30, 2021, 51 full-time City of Lodi positions were authorized specifically to the electric utility department. Contract/temporary employees are hired as necessary. Substantially all of the non-management Lodi personnel assigned to the electric utility department are represented by the International Brotherhood of Electrical Workers, Union 1245 ("IBEW"). The City's current contract with IBEW expired on December 31, 2021. A new contract with IBEW was approved by City Council in January 2022. The current contract expires on December 31, 2024.

Pension Plans. Retirement benefits to City of Lodi employees, including those assigned to the electric utility department, are provided through the City of Lodi's participation in 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. Copies of the CalPERS annual financial report may be obtained from the CalPERS Executive Office, 400 Q Street, Sacramento, California 95814.

Lodi's defined benefit pension plans, the Miscellaneous Plan and the Safety Plan of the Lodi, provide retirement and disability benefits, annual cost-of-living adjustments, and death benefits to plan members and beneficiaries for all Lodi employees. Benefit provisions under the plans are established by State statute and local government resolution. No employees assigned to electric utility department participate in the Safety Plan.

Active Miscellaneous Plan members hired prior to January 1, 2013 are required to contribute 7.00% of their annual covered salary and those hired on or after January 1, 2013 are required to contribute 6.75%

of their annual covered salary. Lodi's employer contribution rate is determined annually by the actuary 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 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. Lodi is required to contribute the difference between the actuarially determined rate and the contribution rate of employees. The actuarial methods and assumptions used are those adopted by the CalPERS Board of Administration. In early 2019, the City finalized a contract amendment with CalPERS for all bargaining units except IBEW. For Miscellaneous Plan members, all non-IBEW employees are contributing between 1% and 3% of salary towards the City's employer cost. As part of the subsequently approved contract between IBEW and the City, IBEW contributes 2% of salary towards the City's employer cost as part of the cost sharing agreement already in place. The 2% contribution has been implemented on a tier basis with 1% cost sharing starting July 2020 and 1% in January 2021. The contribution requirements of the plan members are established by State statute and the employer contribution rates are established, and may be amended, by CalPERS.

California Assembly Bill 340, the Public Employee's Pension Reform Act ("PEPRA"), implemented new benefit formulas and final compensation periods, as well as new contribution requirements for new employees hired on or after January 1, 2013, who meet the definition of a new member under PEPRA. As of January 31, 2021, there are [13] PEPRA members in the electric utility and [32] classic members. ***{Update}*** As more PEPRA members are hired in the future, the annual normal cost of the pension plan should be reduced. Because the unfunded accrued liability of the plan is tied to current shortfalls in the pension system it is not directly impacted by the hiring of PEPRA members.

The table below sets forth Lodi's electric utility department's allocated share of Lodi's required contributions to the Miscellaneous Plan for the past five fiscal years. The amount budgeted for the electric utility department's allocated share of Lodi's estimated required contributions to such plan for Fiscal Year 2021-22 is $1,236,560.

	City of Lodi Miscellaneous Plan		
Fiscal Year Ended June 30	**Electric Utility Department Allocated Share**	**Total City Required Contribution Amount**	**Contributions as a % of Covered Payroll**
2017	$ 958,028	$3,880,495	21.80%
2018	1,097,633	4,208,873	23.42
2019(1)	1,281,978	4,907,206	25.83
2020(1)	1,512,010	4,879,985	26.73
2021(1)	1,249,190	5,323,688	27.51

(1) In fiscal years 2018-19, 2019-20 and 2020-21, Lodi made additional discretionary payment contributions to the Miscellaneous Plan exceeding its actuarially determined required contributions. Total contributions for the Miscellaneous Plan made by Lodi for such fiscal years were as follows: For fiscal year 2018-19, $5,002,406 (representing 25.83% of covered payroll), for fiscal year 2019-20, $5,496,434 (representing 30.10% of covered payroll); and for fiscal year 2020-21 $9,611,114 (representing 49.66% of covered payroll).

Source: City of Lodi.

Lodi's required contributions to CalPERS fluctuate each year and, as noted, 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 Lodi's required contributions to CalPERS in future years. Accordingly, Lodi cannot provide any assurances that

Lodi'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 assumptions used to determine the actuarial accrued liabilities may be found in Lodi's most recent audited financial statements which are available on Lodi's website at *http://www.lodi.gov*.

On December 21, 2016, the CalPERS Board of Administration voted to lower the pension plan's assumed rate of return for purposes of its actuarial valuations from 7.5% to 7.0% by 2020 (which reduction has been phased in over the period from fiscal year 2017-18 to 2019-20). The impact of each reduction in the rate of return will be phased in over five years, with the full impact realized in the 2024-25 fiscal year. CalPERS has estimated that with a reduction in the rate of return to 7.0%, most employers could expect a 1% to 3% increase in the percentage of payroll contribution for the normal cost for miscellaneous plans. In addition, CalPERS has estimated that employers could expect gradual increases in their unfunded accrued liability payment, reaching an approximate increase in such payment (relative to the unfunded accrued liability payments projected in the June 30, 2015 valuation report) of 30% to 40% by fiscal year 2024-25 for miscellaneous plans. As a result, required contributions of employers, including Lodi, toward unfunded accrued liabilities, and as a percentage of payroll for normal costs, are expected to increase.

The announcement on July 12, 2021 that CalPERS achieved a preliminary investment return of 21.3% for the period from July 1, 2020 through June 30, 2021 caused the CalPERS Board of Administration to lower CalPERS' discount rate from 7.0% to 6.8% on November 15, 2021 in accordance with a risk mitigation policy that was adopted in 2015, which calls for the discount rate to be lowered if returns exceed the then-current discount rate by two or more percentage points. Lowering the discount rate generally means that employers which contract with CalPERS to administer their pension plans will see increases in their normal costs and unfunded actuarial liabilities.

The City of Lodi anticipates total pension costs approximately doubling by fiscal year 2024-25 as compared to fiscal year 2017-18. To address the issue, the City has adopted a Pension Stabilization Policy ("PSP") and created a Pension Stabilization Fund ("PSF"). As of December 31, 2021, $21,245,657.13 was set aside in the PSF, an Internal Revenue Service Section 115(c) trust fund established for the purposes of paying future pension liabilities. The PSP requires 100% of General Fund reserves in excess of the 16% General Fund reserve target be deposited into the PSF, and all other funds invest a proportional share based on the budgeted pension obligations in that fiscal year. The PSP remains in effect until the funded status of the Lodi's two pension plans for Miscellaneous and Safety employees are at a combined 80% funded status when considering the Market Value of Assets at CalPERS and in the PSF. As of the June 30, 2020 actuarial report (the most recent available report), the funded status for the Miscellaneous Plan was 68.2%, the funded status for the Safety plan was 58.3% and the funded status for the combined plans was 63.2%. As of December 31, 2021, the combined funded status when considering the PSF assets increases to 68.1%. Based on fiscal year ending June 30, 2021 combined normal cost and UAL pension payments, the electric utility is responsible for approximately 11.2% of the total pension liability for the Lodi.

Effective for the fiscal year ended June 30, 2015, Lodi adopted Governmental Accounting Standards Board ("GASB") Statement No. 68 ("GASB No. 68"), affecting the reporting of pension liabilities for accounting purposes. Under GASB 68, Lodi 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 Net Pension Liability of the Miscellaneous Plan as of June 30, 2016 through June 30, 2020 (as reported in Lodi's audited financial statements as of the succeeding fiscal year). The electric utility department's allocable share of Lodi's net pension liability was not separately determined.

Measurement Date[1] (June 30)	City of Lodi Miscellaneous Plan Net Pension Liability	Net Position as a % of Total Pension Liability	Net Pension Liability as a % of Covered Payroll
2016	$50,988,449	70.65%	292.64%
2017	58,225,070	69.44	324.01
2018	58,379,934	70.37	307.33
2019	60,469,988	70.36	331.20
2020	63,329,327	69.81	327.20

(1) Measured using prior fiscal year annual actuarial valuation rolled forward to measurement date using standard update procedures.

Source: City of Lodi.

As of the June 30, 2020 measurement date, the total pension liability for the Miscellaneous Plan for the City of Lodi was $209,775,815 and the plan fiduciary net position was $146,446,488, resulting in a city-wide Miscellaneous Plan net pension liability of $63,329,327. In the June 30, 2019 actuarial valuation utilized for measuring the pension liability as of the June 30, 2020 measurement date, the Entry Age Normal Actuarial Cost Method was used. The actuarial valuation assumptions used for determining pension liabilities included (a) a 7.25% investment rate of return (net of pension plan investment expenses); (b) an inflation rate of 2.63% per year; and (c) a discount rate of 7.15%.

Retiree Health Benefits. Lodi also provides medical benefits to eligible city employees, including those assigned to Lodi's electric utility department, who retire from Lodi, through the City of Lodi Other Post Employment Benefit Plan (the "OPEB Plan"), through the CalPERS healthcare programs. Lodi's electric utility department only has miscellaneous employees participating in Lodi's plan.

Lodi contributes the minimum provided under California Government Code Section 22825 of the Public Employees Medical and Hospital Care Act. In general, retirees must contribute any premium amount in excess of Lodi's contribution. However, a closed group of certain active employees and retirees receive additional postemployment benefits. Certain employees hired prior to certain dates (depending on the employee bargaining unit) not later than December 6, 1995 are allowed to convert their accumulated sick leave into postemployment medical benefits as long as they have 10 or more years of service with Lodi.

Lodi's contributions to the OPEB Plan are generally based on pay-as-you-go financing. In fiscal year 2016-17, the Lodi City Council authorized the City Manager to deposit an additional $1,000,000 with CalPERS in an OPEB trust fund to pre-fund future benefit payments (the "OPEB Trust Fund"). In fiscal year 2020-21, a Pension Stabilization Funding Policy was approved that required funds in excess of the required reserve balance in the city's locally held benefit fund be deposited into the OPEB trust fund. As of December 31, 2021, the OPEB trust fund balance was $2,486,210.22.

Effective beginning in fiscal year 2017-18, Lodi 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 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.

The table below sets forth certain information regarding the electric utility department's allocated share of Lodi's OPEB contributions for the fiscal years 2017-18 through 2020-21. The amount budgeted for Lodi electric utility department's share of OPEB Plan contributions for fiscal year 2021-22 is $241,600.

City of Lodi OPEB Plan		
Fiscal Year Ended June 30	**OPEB Contribution**	**Electric Utility Allocated Share of City Contribution**
2018	$2,015,770	$261,630
2019	1,988,880	259,590
2020	1,869,590	234,880
2021	1,836,120	227,970

Source: City of Lodi.

Pursuant to GASB No. 75, for the fiscal year ended June 30, 2021, Lodi reported a net OPEB liability of $24,358,432 (reflecting a total OPEB liability of $26,361,543 and a fiduciary net position of $2,003,111 for the OPEB Plan). The net OPEB liability as a percentage of covered-employee payroll was 71.09%. The OPEB Plan Net Position as a percentage of Lodi's total OPEB liability was 7.60%. The net OPEB liability was measured as of June 30, 2020 and the total OPEB liability used to calculate the net OPEB liability was determined by a June 30, 2019 actuarial valuation, based on actuarial methods and assumptions. The actuarial assumptions include: (a) a 6.00% investment rate of return; (b) payroll growth of 2.75%; (c) a 2.50% inflation rate; (d) an annual health care cost trend rate of 6.4% initially, reducing in decrements to 4.00%; and (e) a discount rate of 3.56%.

Additional information regarding the City of Lodi's retirement plans and other post-employment benefits can be found in the City's annual comprehensive financial reports, which may be obtained at *http://www.lodi.gov*.

Insurance

Lodi's boiler and machinery operations (including those parts of the electric system) are insured by the Alliant Property Insurance Program (APIP) which is a group purchase property program through the Lloyd's of London marketplace and Hallmark Financial Services for up to $100 million in coverage. Lodi (including the electric system), is self-insured for general liability losses for up to $500,000 and has pooled excess coverage through the California Joint Powers Risk Management Authority for up to $40 million per occurrence. Effective July 1, 2022, Lodi's self-insured retention will increase to $750,000. Lodi (including the electric system) is self-insured for workers' compensation losses for up to $250,000 and has excess coverage through the Local Agency Workers' Compensation Excess Joint Powers Authority for statutory coverage.

Litigation

There is no action, suit or proceeding known to be pending or threatened, restraining or enjoining Lodi in the execution or delivery or performance of, or in any way contesting or affecting the validity of any proceedings of Lodi taken with respect to, the Third Phase Agreement.

There is no litigation pending, or to the knowledge of Lodi, threatened, questioning the existence of Lodi, or the title of the officers of Lodi to their respective offices. There is no litigation pending, or to the knowledge of Lodi, threatened, questioning or affecting in any material respect the financial condition of Lodi's electric system.

Present lawsuits and other claims against Lodi's electric system are incidental to the ordinary course of operations of the electric system and are largely covered by Lodi's self-insurance program. In the opinion of Lodi's management and the Lodi City Attorney, such claims and litigation will not have a materially adverse effect upon the financial position of Lodi.

Lodi's Operations Since Industry Restructuring

Since the deregulation of the California energy markets, Lodi has implemented revenue enhancements, cost containment measures and changes in operating procedures to help mitigate financial risks associated with changes in market power costs. See "CERTAIN FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY – State Legislation and Regulatory Proceedings" in the front part of this Official Statement. These actions include:

- Energy Cost Recovery. Implemented an ECA for all customers. This rate action guarantees coverage of bulk power purchase costs. See "– Rates and Charges" above.

- Risk Management Program. Lodi established an Energy Risk Management Policy, most recently updated by the City's Risk Oversight Committee in August 2021. Consistent with the policy Lodi has established guidelines which provide a time and price triggered tier approach to closing open positions as long as five years into the future. The table below illustrates this approach:

Month	**Covered Position As % of Forecasted Load**					
0 designates current month	>60th	60th	50th-Median	25th	10th	<10th
1-3	80-90%	85-95%	95%	95%	95%	100%
3+	80-90%	85-95%	85-95%	95%	95%	100%
6+	70-80%	75-85%	80-90%	85-95%	95%	100%
9+	60-70%	65-75%	70-80%	75-85%	85-95%	90%
12+ months	60-70%	65-75%	70-80%	75-85%	85-95%	90%

The above guidelines were updated in 2019 to expand hedging efforts when forecasted prices are historically low to mitigate future price risk/volatility.

The Energy Risk Management Policy applies to all aspects of Lodi's wholesale procurement and sales activities, long-term contracting associated with energy supplies, and associated financing related to generation, transmission, transportation, storage, Renewable Energy Credits (RECs), Greenhouse Gas (GHG) offsets, Resource Adequacy (RA) capacity, ancillary services and participation in Joint Powers Agencies (JPAs).

Significant Accounting Policies

Lodi's most recent ACFR for the fiscal year ended June 30, 2021 was audited by The Pun Group, Walnut Creek, California, in accordance with generally accepted auditing standards, and contains opinions that the financial statements present fairly the financial position of the various funds maintained by Lodi. The reports include certain notes to the financial statements which may not be fully described below. Such notes constitute an integral part of the audited financial statements. Copies of these reports are available on request from the City of Lodi, Finance Department, 310 West Elm Street, Lodi, California 95240 or at *http://www.lodi.gov*. Governmental accounting systems are organized and operated on a fund basis. A fund is defined as an independent fiscal and accounting entity with a self-balancing set of accounts recording cash and other financial resources, together with all related liabilities and residual equities or balances, and changes therein. Funds are segregated for the purpose of carrying on specific activities or attaining certain objectives in accordance with special regulations, restrictions or limitations.

The electric system is accounted for as an enterprise fund. Enterprise funds are used to account for operations (i) that are financed and operated in a manner similar to private business enterprises (where the intent of the governing body is that the costs (expenses, including depreciation) of providing goods or services to the general public on a continuing basis be financed or recovered primarily through user charges) or (ii) where the governing body has decided that periodic determination of revenues earned, expenses incurred and/or net income is appropriate for capital maintenance, public policy, management control, accountability or other purposes.

The accounting policies of Lodi conform to generally accepted accounting principles (GAAP) as applicable to governments.

Condensed Operating Results and Selected Balance Sheet Information

The following table sets forth summaries of operating results and selected balance sheet information of Lodi's electric utility for the five fiscal years 2016-17 through 2020-21. The information for the fiscal years ended June 30, 2017 through June 30, 2021 was prepared by Lodi on the basis of its audited financial statements for such years. However, the figures shown are calculated in accordance with the documents pursuant to which Lodi's outstanding electric system revenue obligations were issued, which may or may not be on the same basis as GAAP, and as such, do not match the line item designations in Lodi's audited financial statements.

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CITY OF LODI
ELECTRIC UTILITY DEPARTMENT
SUMMARY OF OPERATING RESULTS AND SELECTED BALANCE SHEET INFORMATION[1]
($ in 000s)

	Fiscal Year ended June 30,				
	2017	**2018**	**2019**	**2020**	**2021**
OPERATING REVENUES:					
Rate Revenue	$64,114	$65,054	$63,776	$64,795	$68,193
ECA Revenue	1,734	4,192	4,186	7,386	6,004
Other Revenue	1,967	3,475	4,155	6,460	3,711
Total Operating Revenues	67,815	72,721	72,117	78,641	77,908
OPERATING EXPENSES:					
Purchased Power[2]	35,650	39,519	37,043	40,863	41,501
Non-Power Costs[3]	16,609	16,422	14,289	18,404	16,601
Total Operating Expenses	52,259	55,941	51,332	59,267	58,102
NET REVENUE AVAILABLE FOR DEBT SERVICE:	15,556	16,780	20,785	19,374	19,806
Debt Service – 2018 Bonds	--	--	1,497[5]	3,748	4,189
Debt Service – 2008 A Bonds	5,288	5,298	0	0	0
Remaining After Debt Service	10,268	11,482	19,288	15,626	15,617
OTHER REVENUES (EXPENSES):					
Greenhouse gas allowance	2,370	559	94	--	312
Impact Fees	--	138	245	265	568
PERS Stabilization Contribution	--	(603)	(204)	(244)	--
Payments in Lieu of Taxes[4]	(7,131)	(7,159)	(7,197)	(7,274)	(7,375)
Net Cash Flow Before Capital Expenditure	$ 5,507	$ 4,417	$ 12,226	$ 8,373	$ 9,122
SELECTED BALANCE SHEET INFORMATION:					
Net Plant in Service	$ 7,957	$ 7,808	$ 7,495	$ 7,181	$ 6,861
Land and Construction Work in Progress	$ 764	$ 764	$ 764	$ 764	$ 764
Long-Term Debt	$58,669	$48,291	$48,291	$46,220	$43,274
Debt Service Coverage Ratio[1]	2.94	3.17	13.88[5]	5.17	4.73

(1) Figures shown are calculated in accordance with the documents pursuant to which Lodi's outstanding electric system revenue obligations were issued, which may or may not be on the same basis as GAAP. See "– Indebtedness; Joint Powers Agency Obligations."
(2) Purchased Power includes joint powers agency payment obligations.
(3) Non-power costs include costs of services provided by other departments and does not include depreciation or amortization expense.
(4) Payments in-lieu of taxes are made by the Electric System to the City's general fund. The City's in-lieu payment is based upon a base transfer amount established by the City Council in 2007 adjusted annually by the number of electric customers served.
(5) Debt service was reduced in fiscal year 2018-19 as a result of the refunding of outstanding electric system obligations effected by the referenced 2018 Bonds. Scheduled debt on Lodi's currently outstanding direct electric system obligations is approximately $3.7 million service in fiscal year 2019-20 and approximately $4.0 million annually thereafter.

Source: City of Lodi.

CITY OF PALO ALTO

Introduction

The City of Palo Alto ("Palo Alto") is a charter city of the State of California. Pursuant to the California Constitution, Palo Alto's City Charter, and its municipal code, Palo Alto has the power to furnish electric utility service to its inhabitants. In connection therewith, Palo Alto has the powers of eminent domain, to contract, to construct works, to fix rates and charges for commodities or services furnished and to incur indebtedness.

Palo Alto provides electric and other utility services through its department of utilities (the "Department of Utilities"). The legal responsibilities and power of the Department of Utilities, including the establishment of rates and charges, are exercised through the seven member Palo Alto City Council. The members of the City Council are elected citywide for staggered four-year terms. The Palo Alto Department of Utilities is under the direction of the General Manager of Utilities who is accountable to the City Manager and who is appointed by the City Manager with the approval of the City Council.

Since 1900, Palo Alto has provided all electric service within the City of Palo Alto. For the fiscal year ended June 30, 2021, Palo Alto served 29,850 customers, had total sales of approximately 814 million kWh and a peak demand of 159 MW.

To provide electric service within its service area, Palo Alto owns and operates an electric system which includes power supply resources and transmission and distribution facilities. Palo Alto also purchases power and transmission services from others and participates in pooling and other utility type arrangements. In addition, Palo Alto provides gas utility and other normal city services to its inhabitants such as police and fire protection and water and sewer service.

In 2011, the California Legislature passed Senate Bill X1-2 ("SBX1-2"), the "California Renewable Energy Resources Act." SBX1-2 requires local publicly owned utilities to adopt and implement a renewable energy resource procurement plan to achieve specified targets for serving their retail energy loads from eligible renewable energy resources.

In March 2011, the Palo Alto City Council approved the updated Long-Term Electric Acquisition Plan ("LEAP") Objectives, Strategies and Implementation Plan. LEAP provides high level policy direction for the pursuit of energy efficiency, demand resources, renewable energy, local generation and transmission resources. LEAP also sets direction for the management of hydroelectric resources and market exposure uncertainty. LEAP was updated in March and April 2012 to include revisions related to Palo Alto's energy storage targets and Renewable Portfolio Standard ("RPS").

In 2013, the Palo Alto City Council approved a Carbon Neutral Electric Resource Plan (the "Carbon Neutral Plan"), which defined carbon neutrality for Palo Alto's electric portfolio, demonstrated a transparent and verifiable protocol to measure carbon content and established a goal to achieve carbon neutrality by the end of 2013. As a result, Palo Alto has neutralized all greenhouse gas emissions associated with the City's electric portfolio since 2013, putting the City of Palo Alto on track to achieve its Sustainability and Climate Action Plan greenhouse gas emission reduction goal of 80% emissions reduction from 1990 levels by 2030. See "– Future Power Supply Resources – *Carbon Neutral Plan*" below.

In 2015, the California Legislature passed Senate Bill 350 ("SB 350"), the "Clean Energy and Pollution Reduction Act of 2015." SB 350 increased California's renewable electricity procurement goal from 33% by 2020 to 50% by 2030 based on RPS-eligible resources. SB 350 also requires Palo Alto to develop and submit an Integrated Resource Plan for the electric utility every four years, with the first required to be adopted by the Palo Alto City Council by January 1, 2019. In 2018, the California Legislature passed Senate Bill 100 ("SB 100"), the "100 Percent Clean Energy Act of 2018." SB 100 accelerates the State's RPS target as established by SB 350 from 50% by 2030 to 60% by 2030 and sets a goal of 100% "clean energy" by the year 2045. See also "CERTAIN FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY – State Legislation and Regulatory Proceedings" in the front part of this Official Statement for more information on SB 350 and SB 100.

In 2017, Palo Alto kicked-off a process to develop its Electric Integrated Resource Plan ("EIRP") for the 2019 to 2030 planning horizon. The EIRP updates LEAP and maps out Palo Alto's long-term plan for achieving its electric energy, capacity and reliability needs through the use of distributed energy resources ("DER"), such as energy efficiency and solar photovoltaics, and carbon neutral supply resources. The EIRP was approved by the Palo Alto City Council in December 2018 and submitted to the California Energy Commission (the "CEC") in April 2019. This document serves as the City's Integrated Resource Plan for the purpose of meeting California's integrated resource planning compliance requirements for local publicly owned utilities under SB 350.

Palo Alto has a comprehensive Energy Risk Management Program governing electric and natural gas transactions. The program consists of the Palo Alto City Council approved policies, and operational guidelines approved by Palo Alto City's Risk Oversight and Coordination Committee. The Energy Risk Management Program segregates commodity purchase and sale functions related to the front, middle and back offices.

Only the revenues of the Palo Alto electric utility will be available to pay amounts owed by Palo Alto under the Third Phase Agreement.

The main offices of the City of Palo Alto Department of Utilities are located at 250 Hamilton Avenue, 3rd Floor, Palo Alto, California 94301 (650) 329-2161. For more information about Palo Alto and its Department of Utilities, contact Dean Batchelor**,** General Manager of Utilities, at the above address and telephone number. A copy of the most recent annual comprehensive financial report of the City of Palo Alto (the "Annual Report") is available on Palo Alto's website at *http://www.cityofpaloalto.org* and on the Municipal Securities Rulemaking Board's Electronic Municipal Market Access system at *http://emma.msrb.org*/. The Annual Report is incorporated herein by this reference. However, the information presented on such website or referenced therein other than the Annual Report is not part of this Official Statement and is not incorporated by reference herein.

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Power Supply Resources

The following table sets forth information concerning Palo Alto's power supply resources and the energy supplied by each during the fiscal year ended June 30, 2021.

CITY OF PALOALTO
DEPARTMENT OF UTILITIES
POWER SUPPLY RESOURCES
For the Fiscal Year Ended June 30, 2021

Source	Capacity Available (MW)	Actual Energy (GWh)	Percent of Total Energy
Purchased Power:			
Solar	130	311	38%
Wind	21	120	15
Landfill Gas Energy	14	104	13
Western (Hydro)	182	246	30
NCPA			
Hydroelectric Project	58	49	6
Geothermal Project[1]	--	--	--
Net Forward Market Sales/Purchases[2]	60	(30)	(4)
Net Spot Market Sales/Purchases	--	27	3
Total	N/A[3]	827	100%

(1) Capacity and energy sold to Turlock Irrigation District. See "– Joint Powers Agency Resources – *NCPA*" below.
(2) See "– Purchased Power – *Other Power Purchases*" below.
(3) Capacity availability varies by season and is not necessarily additive at any given time.
Source: City of Palo Alto.

In the fiscal year ended June 30, 2021, Palo Alto's average cost of power delivered to the Palo Alto electric system was approximately 10.0 cents per kWh.

Purchased Power

Western. Palo Alto receives a substantial portion of its supply of power from the Central Valley Project ("CVP') pursuant to a contract with the Western Area Power Administration ("Western").

In October 2000, Palo Alto signed a 20-year agreement with Western (the "Western Base Resource Contract") for the continued purchase of hydroelectricity from the CVP. Service under such Western Base Resource Contract began on January 1, 2005 and continues through 2024, with Palo Alto receiving an 11.620% "slice of the system" allocation from Western. On January 1, 2015, Palo Alto's allocation increased to 12.309%. The power marketed by Western to Palo Alto is provided on a take-or-pay basis where Western's annual costs are allocated to preference customers based on their CVP participation percentage. Western then allocates the annual take-or-pay charges to the preference customers based on a monthly percentage that is designed to reflect the anticipated seasonal energy deliveries. Palo Alto is obligated to its preference customer share of the costs associated with operating the CVP facilities. Palo Alto's energy allocation under the current Western Base Resource Contract starting in January 2005 is approximately 365 GWh/year in an average hydrological year. Palo Alto's annual cost obligation under the Western Base Resource Contract is approximately $14 million per year, resulting in an average cost of approximately $38 per MWh in an average hydrological year. In February 2021, Palo Alto approved a new 30-year Western Base Resource Contract, with a 12.063% allocation, that will begin on January 1, 2025.

Wind Energy Contracts. Palo Alto currently has one long-term contract for the output of wind electricity generation. Under a contract with Avangrid Renewables (formerly Iberdrola Renewables and PPM Energy, Inc.) ("Avangrid"), for power from the High Winds I project (owned by NextEra Energy Resources, LLC (formerly FPL Energy, LLC)) in Solano County, Palo Alto is allocated available capacity of 20 MW and acquired a fixed unit price on expected generation of 43 GWh/year. The term of the High Winds I contract ends in 2028.

Landfill Gas Energy Contracts. Palo Alto currently has five long-term contracts for the output of landfill gas electricity generation under separate contracts with Ameresco, Inc. Under the first contract with Ameresco Santa Cruz Energy, L.L.C., for power from the Santa Cruz project (at a landfill owned by County of Santa Cruz) in Watsonville, California, Palo Alto is allocated available capacity of 1.5 MW and acquired an initial fixed per-unit price with 1.5% annual increases on expected generation of 9.0 GWh/year. The Santa Cruz project began commercial operation in February 2006 and its contract term ends in 2026. Under a second contract with Ameresco Half Moon Bay, L.L.C., for power from the Ox Mountain project (at a landfill owned by Republic Services, Inc.) in Half Moon Bay, California, Palo Alto is allocated available capacity of 5.1 MW and acquired an initial fixed per-unit price with 1.5% annual increases on expected generation of 42.5 GWh/year. The Ox Mountain project began commercial operation in April 2009 and its contract term ends in 2029. Under a third contract with Ameresco Keller Canyon, L.L.C., for power from the Keller Canyon project (at a landfill owned by Republic Services) in Pittsburg, California, Palo Alto is allocated available capacity of 1.5 MW and acquired an initial fixed per-unit price with 1.5% annual increases on expected generation of 13.8 GWh/year. The Keller Canyon project began commercial operation in August 2009 and its contract term ends in 2029. Under a fourth contract with Ameresco Johnson Canyon, L.L.C., for power from the Johnson Canyon project (at a landfill owned by Salinas Valley Solid Waste Authority) in Gonzales, California, Palo Alto is allocated available capacity of 1.4 MW and acquired an initial fixed per-unit price with 1.5% annual increases on expected generation of 9.2 GWh/year. The Johnson Canyon project began commercial operation in May 2013 and its contract term ends in 2033. Under a fifth contract with Ameresco San Joaquin, L.L.C., for power from the San Joaquin project (at a landfill owned by San Joaquin County) in Linden, California, Palo Alto is allocated available capacity of 4.3 MW and acquired an initial fixed per-unit price with 1.5% annual increases on expected generation of 27.5 GWh/year. The San Joaquin project began commercial operation in April 2014 and its contract term ends in 2034.

Palo Alto expects to receive a total of 102 GWh/year from these five landfill gas projects, representing approximately 11% of Palo Alto's load. Each of the foregoing landfill gas energy contracts is unit contingent.

Solar Energy Contracts. Palo Alto currently has six long-term contracts for the output of solar electricity generation under separate contracts with three different parent companies. The first three contracts are with the AES Corporation (AES): the 26.656 MW Hayworth Solar project in Kern County, and the 40 MW Elevation Solar C and 20 MW Western Antelope Blue Sky Ranch B projects in Los Angeles County. These three contracts all feature fixed per-unit prices and produce expected generation of 52 GWh/year, 101 GWh/year, and 50.5 GWh/year, respectively. The terms of such contracts all end in 2041. Palo Alto also has two solar energy contracts with Boralex: the 20 MW Frontier Solar project in Stanislaus County, and the 20 MW EE Kettleman Land project in Kings County. Both of these contracts feature fixed per-unit prices and produce expected generation of 52.5 GWh/year and 53.5 GWh/year, respectively. The term of the Frontier Solar contract ends in 2046, while that of the EE Kettleman Land contract ends in 2040. Finally, Palo Alto has a contract with Clearway Energy for a 26 MW share of the 192 MW Rosamond Central project in Kern County that began operating in January 2021. This contract, for a fixed per-unit price, has a 25-year contract term, and will begin delivering about 75 GWh/year to Palo Alto starting in January 2023.

Palo Alto expects to receive a total of 340 GWh/year from the five operating solar energy projects, representing approximately 39% of Palo Alto's load. When the sixth solar energy project's contract term begins in 2023, Palo Alto expects to receive 385 GWh/year from these projects, representing 45% of Palo Alto's load. Each of the foregoing solar energy contracts is unit contingent.

Other Power Purchases. Palo Alto has nine active Master Agreements with BP Energy, Shell Energy North America, Powerex Corp, Cargill Power Markets, Exelon Generation, Avangrid, NextEra Energy Marketing, Turlock Irrigation District ("TID"), and PacifiCorp to facilitate competitive forward market purchases to meet Palo Alto's loads in the short- to medium-term. As of June 30, 2021, Palo Alto had outstanding electricity purchase commitments for the period July 2021 to June 2022 totaling 31 GWh, and sales commitments for this period totaling 67 GWh. These market-based purchases and sales are made within the parameters of Palo Alto's Energy Risk Management Program.

In fiscal year 2020-21, gross market-based purchases provided approximately 24% of Palo Alto's energy needs, while gross market-based sales equaled 21% of Palo Alto's energy needs. The volume of market purchases and sales however is highly dependent on hydrologic conditions and long-term commitments to renewable resource-based supplies. During normal hydrologic conditions, gross market purchases are expected to meet approximately 18% of energy needs, while gross market sales are expected to amount to approximately 28% of energy needs. All purchase transactions and sales-incidental-to-purchases are designed to meet native load. NCPA serves as Palo Alto's scheduling and billing agent for all transactions, and acts as the interface with the California Independent System Operator ("CAISO") under the Second Amended and Restated Metered Subsystem Aggregation Agreement (the "MSSA"). See "NORTHERN CALIFORNIA POWER AGENCY – NCPA Power Pool" in the front part of this Official Statement.

Joint Powers Agency Resources

NCPA. Except for a small 4.5 MW generator within the City of Palo Alto, Palo Alto does not independently own any generation assets. In addition to purchasing power from other sources, Palo Alto is a participant in certain NCPA projects. Palo Alto has purchased from NCPA a 22.920% entitlement share in the NCPA Hydroelectric Project and a 6.158% entitlement share in the NCPA Geothermal Project. In 1984, Palo Alto permanently assigned its share of the Geothermal Project to TID on a take-or-pay basis for the life of the plant, since Palo Alto's need for base load generation at the time the sale was made was limited. Palo Alto remains, however, secondarily liable for payment of project costs not paid by TID. For each of these NCPA projects in which Palo Alto participates, Palo Alto is obligated to pay, on an unconditional take-or-pay basis, as an operating expense of the Palo Alto electric system, its entitlement share of the debt service on NCPA bonds issued for the project, as well as its share of the operation and maintenance expenses of the project. See also "– Indebtedness; Joint Powers Agency Obligations" below.

For a description of such NCPA resources, see "THE HYDROELECTRIC PROJECT" and "OTHER NCPA PROJECTS" in the front part of this Official Statement.

TANC California-Oregon Transmission Project. Palo Alto is also a member of the Transmission Agency of Northern California ("TANC") and has a participation share of 4.00% (net of layoffs) of TANC's entitlement to transfer capability (approximately 50 MW) of the California-Oregon Transmission Project ("COTP") and is responsible for 4.032% of TANC's COTP operating and maintenance expenses and 4.00% of TANC's aggregate debt service. As a result of low utilization on Palo Alto's part of the transmission capacity and therefore low value relative to costs, in addition to a focus on acquiring in-state renewable resources, in August 2008 Palo Alto effected a long-term assignment of its full share and obligations in

COTP to Sacramento Municipal Utility District ("SMUD"), TID and Modesto Irrigation District ("MID"). The long-term assignment is for 15 years with an option to renew for five years. In March 2016, TANC restructured the long-term debt associated with COTP extending the debt through the end of 2039. Palo Alto's layoff recipients, SMUD, TID and MID, through an amendment to the assignment agreement, agreed to extend the term of the payments under the assignment agreement to continue to pay Palo Alto's portion of the COTP debt during the term of the term of the COTP bonds. For a further description of the TANC COTP project, see "CITY OF ALAMEDA – Transmission Resources – *TANC California-Oregon Transmission Project.*"

Distributed Energy Resources

Distributed energy resources include generation, storage, demand response, and energy efficiency on the distribution system which can change the shape and timing of energy use. Palo Alto has undertaken a comprehensive process to plan to maximize the value of distributed energy resources and is reviewing a coordinated Distributed Energy Resources Plan. In addition, Palo Alto's Electric and Gas Public Benefits and Water Efficiency Programs include programs related to efficiency, renewable energy, low-income discounts, and research, development and demonstration (RD&D) of emerging technologies. Due to increasing supply costs, significant new regulatory requirements, and Palo Alto's desire to promote environmental stewardship, Palo Alto has placed an increased emphasis on energy and water efficiency. Palo Alto continues to pursue cost-effective energy efficiency as a priority in reducing customer bills. Both the EIRP and Palo Alto's Ten-Year Electric Energy Efficiency Goals (2018-2027) affirm that cost-effective energy efficiency remains Palo Alto's highest priority energy resource, given that energy efficiency typically displaces relatively expensive electricity generation, lowers energy bills for customers, and contributes to economic development and job creation. The Gas Utility Long-Term Plan ("GULP") also includes energy efficiency as an important contributor to the energy plan.

Energy Efficiency Savings Goals and Achievements. California Assembly Bill 2021 ("AB 2021") required all local publicly-owned utilities to identify all potentially achievable cost-effective electric efficiency savings and to establish annual targets for energy efficiency ("EE") savings over ten years, with the first set of EE targets to be reported to the CEC on or before June 1, 2007, and updated every three years thereafter. California Assembly Bill 2227 passed in 2012 amended this target, setting the schedule to every four years. Palo Alto adopted its first Ten-Year Energy Efficiency Portfolio Plan in April 2007, which included annual electric and gas efficiency targets between 2008 and 2017, with a ten-year cumulative savings goal of 3.5% of the forecasted energy use. In accordance with California law, the electric efficiency targets were updated in 2010, with the ten-year cumulative savings goal doubling to 7.2% between 2011 and 2020. Since then, increasingly stringent statewide building code and appliance standards have resulted in substantial energy savings. However, these "codes and standards" energy savings cannot be counted toward meeting the utility's EE goals. The ten-year electric efficiency targets were updated again in 2012, with the ten-year cumulative electric efficiency savings being revised downward to 4.8% between 2014 and 2023.

In 2015, SB 350 mandated the State to double statewide energy efficiency savings in electricity and natural gas end uses by 2030, with cost-effective utility energy efficiency programs as one component. In May 2021, City Council adopted the current set of Ten-Year Electric Efficiency Goals, updating the ten-year cumulative electric efficiency savings target to 4.4% between 2022 and 2031. For fiscal year 2019-20, the electric utility achieved electric savings of 0.27% of load through its customer efficiency programs. Cumulative electric efficiency savings since 2006 are approximately 8% of the fiscal year 2020-21 electric usage.

In parallel to the development of Ten-Year Electric Efficiency Goals, Palo Alto adopted its first set of gas efficiency targets in 2007 to reduce gas consumption by 3.5% between 2008 and 2017. In 2010, the gas efficiency targets were updated to reduce use by 5.5% between 2011 and 2020. Similar to the electric side, gas efficiency potential has declined due to recent changes to California's appliance standards and building codes. The ten-year electric efficiency targets were updated again in 2012, with the ten-year cumulative gas efficiency savings being revised downwards to 2.85% between 2014 and 2023. In March 2017, the Palo Alto City Council adopted its current set of Ten-Year Gas Efficiency Goals, updating the ten-year cumulative gas efficiency savings target to 5.1% between 2018 and 2027. For fiscal year 2019-20, the gas utility achieved gas efficiency savings of 0.23% of total gas sales. Cumulative gas efficiency savings since 2006 is about 4.7% of the fiscal year 2020-21 gas usage.

Local Solar Plan. In April 2014, the Palo Alto City Council passed the Local Solar Plan, which set the city-wide goal of meeting 4% of Palo Alto's energy needs from local solar by 2023 and identified a number of strategies to facilitate achieving that goal. These strategies include the development of several solar programs to encourage installation of roof-top solar, such as the existing incentives of the feed-in tariff program and the PV Partners solar rebate program (described below). As of June 2021, all solar installations within the City of Palo Alto generate approximately 2.7% of Palo Alto's annual electricity (from 15.7 MW of installed local solar capacity).

Customer-side Renewable Generation Programs. The following is a description of Palo Alto's customer-side renewable generation programs:

PV Partners: The PV Partners Program encourages photovoltaic or solar electric ("PV") installations on Palo Alto homes and businesses by providing a rebate based on the capacity, measured in watts, of newly installed PV systems. The PV Partners Program continues to be one of the most successful in the State. Rebate funds were fully reserved in April 2016. The effect of the PV Partners program is illustrated by the cumulative total of PV installations under the program. As of June 30, 2021, there were 1,081 PV installations with the total capacity of 10.18 MW (6.4% of Palo Alto's system peak load) that were installed under the PV Partners Program.

Net-Energy Metering Successor Program: Prior to January 1, 2018 residential and commercial customers in Palo Alto who installed approved PV systems were able to sign up for the Palo Alto Net Energy Metering ("NEM") program. Palo Alto reached the NEM cap of 10.8 MW in January 2018 and Palo Alto is now offering a NEM Successor Program instead. The NEM Successor process is integrated with the permitting process, and customers receive a credit for electricity exported to the grid based on Palo Alto's avoided costs.

Palo Alto CLEAN (Clean Local Energy Accessible Now): This feed-in tariff program (referred to as "Palo Alto CLEAN") purchases electricity generated by renewable energy resources located in Palo Alto's service territory and interconnected on the utility-side of the electric meter. The electricity is purchased by Palo Alto for credit to its RPS. The program was launched in 2012 and has been modified over the past few years. On February 3, 2014, the Palo Alto City Council approved a total program capacity of 3 MW at a price of 16.5 cents per kilowatt hour (kWh) fixed for 20 years. On May 8, 2017, the Palo Alto City Council approved minor changes to Palo Alto CLEAN such that the program no longer has a total participation cap for either solar or non-solar eligible renewable energy resources. Palo Alto is currently offering to purchase the output of eligible renewable electric generation systems located in Palo Alto at the following prices:

- For solar energy resources: 16.5 cents per kilowatt hour ("¢/kWh") for a 15-, 20- or 25-year contract term until the subscribed capacity reaches 3 MW; thereafter, the price will drop to 8.8¢/kWh for a 15-year contract term, 8.9¢/kWh for a 20-year contract term, or 9.1¢/kWh for a 25-year contract term; and

- For non-solar eligible renewable energy resources: 8.3¢/kWh for a 15-year contract term, 8.4¢/kWh for a 20-year contract term, or 8.5¢/kWh for a 25-year contract term.

There is no minimum or maximum project size, but the program is best suited for commercial property owners with available roof-tops or parking lots. Palo Alto's Public Works Department recently solicited proposals to install solar PV systems and electric vehicle chargers at four City-owned parking structures. All four City-owned parking garage solar PV systems became operational as of March 2018. As of January 2022, there are a total of six solar PV systems participating in the Palo Alto CLEAN program, including the four aforementioned systems on City-owned parking garages. These six projects account for 2.84 MW of the 3 MW of capacity available at the 16.5¢/kWh contract rate and were all online by June 2019, with contract terms ranging from 14 to 25 years.

Future Power Supply Resources

Carbon Neutral Plan. In March 2013, the Palo Alto City Council approved its Carbon Neutral Plan committing Palo Alto to using carbon neutral electric resources beginning in calendar year 2013. The plan also provides that such resource portfolio adjustments should not result in a rate increase of more than 0.15¢/kWh (equivalent to about $1.00/month for an average residential bill).

Palo Alto's current renewable energy resource policy targets a 50% resource portfolio share by 2030. The policy also provides that such resource portfolio adjustments should not result in a rate increase of more than 0.5¢/kWh (equivalent to about $3.35/month for an average residential bill). Palo Alto also permits its commercial customers to voluntarily participate in a green power program whereby participating customers can elect to pay a premium through their electric rates to purchase renewable energy certificates through Palo Alto for all or a portion of their energy needs.

In accordance with LEAP and the Carbon Neutral Plan, Palo Alto has entered into a number of electricity purchase contracts to meet its resource requirements as described above. As of December 31, 2021, Palo Alto had procured approximately 105% of its total projected electricity needs for fiscal year 2021-22 (assuming the projected hydroelectric production).

Palo Alto satisfied the RPS target under SBX1-2 for Compliance Period 1 (from 2011 through 2013), with an average of approximately 21.3% of Palo Alto's energy portfolio supplied from renewable resources over such period. Palo Alto has also satisfied the RPS target for Compliance Period 2 (from 2014 through 2016), meeting the compliance requirement of 20% of retail sales in 2014 and 2015, and 25% of retail sales in 2016. Palo Alto satisfied the RPS target under SBX1-2 for Compliance Period 3 (from 2017 through 2020), meeting or exceeding a total equal to 27% of retail sales in 2017, 29% of retail sales in 2018, 31% of retail sales in 2019 and 33% of retail sales in 2020 supplied from renewable resources. As of January 2022, Palo Alto has sufficient hydroelectric and renewable generation contracts to provide enough energy to supply its entire load (assuming average hydrologic conditions). See also "CERTAIN FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY – State Legislation and Regulatory Proceedings" in the front part of this Official Statement for more information on SBX1-2.

Going forward, Palo Alto expects to meet its energy needs through energy efficiency and other distributed energy resources, existing hydroelectric generation and renewable resources and additional renewable generation contracts which are expected to begin delivering energy to Palo Alto in 2023. Palo Alto will continue to procure energy supplies to meet Palo Alto's short and medium-term energy needs through market purchases with Palo Alto's pre-selected suppliers.

Interconnections, Transmission and Distribution Facilities

Palo Alto's electric system is directly interconnected with the system of Pacific Gas and Electric Company ("PG&E") by a single 115 kV delivery point at Palo Alto's Colorado substation. Palo Alto receives transmission services under the MSSA between NCPA and the CAISO. See also "CERTAIN

FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY – PG&E Bankruptcy Proceeding" in the front part of this Official Statement.

Palo Alto's distribution system consists of the 115 kV to 60 kV delivery point, two 60 kV switching stations, 9 distribution substations, approximately 12 miles of 60 kV sub transmission lines, and approximately 469 miles of 12 kV and 4 kV distribution lines including 223 miles of overhead lines and 245 miles of underground lines.

The service area of the Palo Alto electric system is coterminous with the municipal boundaries of the City of Palo Alto. A portion of the area within the City limits, west of Highway 280 and known as the "Foothills" area, is in a State-designated high fire threat area. On August 20, 2018, pursuant to the requirements of California Senate Bill 1028, the Palo Alto City Council made a wildfire risk determination with respect to the Foothills area. The Palo Alto electric utility has in place a number of mitigation measures aimed at reducing the risk of a wildfire occurrence being caused by its overhead electrical lines and equipment, which were approved by the City Council in connection with its wildfire risk determination. These measures include: periodic inspection of overhead electric facilities, ongoing vegetation clearance and management activities, and the elimination of the automatic restoration function in the Foothills to require that power to a tripped line is only restored after manual inspection and confirmation that it may be operated safely. Separately, the City of Palo Alto has maintained a Foothills Fire Mitigation Plan since 2009; such plan was most recently updated in 2016. Pursuant to the requirements of California Senate Bill 901 ("SB 901"), the Palo Alto electric utility prepared its own wildfire mitigation plan. Palo Alto most recently presented its wildfire mitigation plan and the independent evaluator's assessment to the City Council on January 21, 2020, and to its Utilities Advisory Commission on June 6, 2021. See "CERTAIN FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY – State Legislation and Regulatory Proceedings – *Legislation Relating to Wildfires; Related Risks*" in the front part of this Official Statement.

COVID-19

The spread of the novel strain of coronavirus (and variants thereof) and the disease it causes (now known as "COVID-19") has had significant negative impacts throughout the world, including in California. In 2020, the World Health Organization declared the COVID-19 outbreak to be a pandemic, and states of emergency have been declared by the United States, the State and numerous counties throughout the State. The purpose behind these declarations was to coordinate and formalize emergency actions across federal, state and local governmental agencies, and to proactively prepare for a wider spread of the virus.

On March 19, 2020, in an effort to slow the spread of COVID-19, Governor Newsom issued Executive Order N-33-20 ordering individuals living in the State to stay home or at their place of residence except for specified exceptions, including exceptions for certain sectors of the workforce that were classified as providing essential services and products, which allowed businesses and workers in such sectors to continue to operate on-site operations while Executive Order N-33-20 was effective. On June 11, 2021, Governor Newsom issued two executive orders, which became effective on June 15, 2021, which had the effect of rescinding a majority of the COVID-19-related restrictions and providing a timeline for gradually lifting certain of the other restrictions that were not fully rescinded on June 15, 2021.

During the pandemic, Palo Alto has experienced a decline in electricity demand by the commercial sector while electricity usage by the residential sector increased, as might be expected with many retail establishments being closed and people staying home. See "Customers, Energy Sales, Revenues and Demand."

Historically, the annual write-offs for uncollectible accounts have been less than 0.01% of gross billings of the Palo Alto electric system. Since the onset of the COVID-19 pandemic, write-offs for uncollectible accounts has increased to approximately 0.04% of gross billings for fiscal year 2020-21. To help mitigate the economic impact of COVID-19 and the related governmental regulations on its customers, Palo Alto implemented a payment deferral program for all customers of Palo Alto utilities, which included the suspension of the disconnection of services and dunning by City utilities for non-payment of utility bills for a period beginning in March 2020 and extending through June 2022.

Palo Alto was allocated approximately $0.736 million under the California Department of Community Services and Development California Arrearage Payment Program ("CAPP"), to aid the accounts that have fallen behind during the period of May 4, 2020 through June 15, 2021, which in turn is expected by Palo Alto to lower the uncollectible revenue amount. Palo Alto received the funding in January 2022.

With widespread vaccination currently underway in the United States and many countries worldwide, governmental-imposed stay-at-home orders and restrictions on operations of schools and businesses implemented to respond to and control the outbreak have been eased or eliminated. However, restrictions may be re-imposed in various jurisdictions from time to time as local conditions warrant. Palo Alto cannot predict whether any reinstatement or expansion of stay-at-home orders and travel or other restrictions will occur or when a full resumption of all economic activity will be achieved. The ultimate impact of COVID-19 on the operations and finances of Palo Alto is unknown and there can be no assurances that COVID-19 will not materially adversely impact the financial condition of Palo Alto or the electric system in the future. There are many variables that will continue to contribute to the economic impact of the COVID-19 pandemic and the recovery therefrom, including the length of time social distancing measures are in place, the effectiveness of State and federal government relief programs and the timing for containment and treatment, new coronavirus strains, vaccinations efforts and vaccine hesitancy. Palo Alto cannot predict the extent or duration of such impacts.

Rates and Charges

The Palo Alto City Council is authorized by the Palo Alto Municipal Code to set fees and charges, pay for and supply all electric energy and power to be furnished to customers according to such schedules, resolutions, rules and regulations as are adopted by the City Council. These rates are not subject to review by any State or federal agency. In addition, the City Charter provides for the maintenance of a separate fund for each utility into which is deposited receipts from the operations of such utilities and from which are payable the utility's costs and expenses, including operating and maintenance, debt service, capital expenditures, funding of reserves, and general fund transfers.

Palo Alto's fiscal year 2020-21 average rates per kWh for all service was 15.9 cents. Palo Alto's fiscal year 2020-21 average rates for commercial and industrial service was 15.8 cents per kWh. Palo Alto's fiscal year 2020-21 average rate per kWh for residential service was 16.4 cents.

The following table presents a history of Palo Alto's electric utility rate increases since 2017.

CITY OF PALO ALTO
DEPARTMENT OF UTILITIES
RATE CHANGES

Date	Percent Change
July 1, 2021	0.00%
July 1, 2020	0.00
July 1, 2019	8.00
July 1, 2018	6.00
July 1, 2017	14.0

Source: City of Palo Alto.

Palo Alto spends approximately 2.85% of gross electric revenues on the public benefit programs it originally developed in response to California Assembly Bill 1890, which was adopted in 1996 ("AB 1890"). In addition to funding available through the public benefits program, Palo Alto funds additional efficiency and renewable energy programs through the electric utility's supply resource acquisition budget.

Low-Income Programs

The following is a description of Palo Alto's low-income assistance programs:

- ***Residential Energy Assistance Program (REAP)***. This program provides qualifying low-income residents with free energy efficiency measures and access to the Rate Assistance Program (RAP) rate discount. For qualifying customers, a Home Assessment, an application to the RAP, and an on-site customer evaluation for weatherization and energy efficiency measure installation, including insulation and lighting, is provided. Customers may have refrigerators and/or furnaces replaced if the need is found.

- ***Rate Assistance Program (RAP)***. This program provides a 25% discount for electric and gas charges for qualified customers. Applicants can qualify based on medical or financial need.

- ***Project PLEDGE.*** This program provides a one-time contribution of up to $750 applied to the utilities bill of qualifying residential customers. Eligibility criteria includes recent emergency events for employment and health. Administered by the Department of Utilities, this program is funded by voluntary customer contributions.

Largest Customers

The ten largest customers of Palo Alto's electric utility system, based upon energy usage for the fiscal year ended June 30, 2021 accounted for approximately 38.1% of total kWh sales and approximately 33.9% of total electric revenues. The largest account consumed 9.4% of Palo Alto's total kWh sales and contributed 8.1% of total revenues and the smallest of the ten largest accounts accounted for 2.0% of total kWh sales and 1.9% of revenues.

Customers, Energy Sales, Revenues and Demand

The average number of customers, kWh sales, revenues derived from sales by classification of service and peak demand during the five fiscal years 2016-17 through 2020-21, are s below.

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CITY OF PALO ALTO
DEPARTMENT OF UTILITIES
CUSTOMERS, SALES, REVENUES[1] AND DEMAND[2]
Fiscal Year Ended June 30,

	2017	2018	2019	2020	2021
Number of Customers:					
Residential	25,642	25,502	25,675	25,326	25,074
Commercial	3,753	3,788	3,703	3,665	3,599
Industrial	85	79	72	68	62
Other	136	144	141	143	143
Total	29,616	29,513	29,591	29,202	28,878
Kilowatt-Hour Sales (in thousands):					
Residential	148,986	150,064	150,602	154,510	165,103
Commercial	580,832	578,218	568,751	551,244	501,635
Industrial	157,502	141,387	133,791	123,237	122,155
Other	30,368	29,780	29,258	25,681	24,992
Total	917,687	899,449	882,403	854,672	813,885
Revenues from Sale of Energy:					
Residential	$ 20,269	$ 22,764	$23,613	$25,466	$26,719
Commercial	73,471	82,299	85,332	89,063	81,235
Industrial	17,164	17,901	18,177	18,272	17,347
Other	3,780	4,264	4,404	4,286	4,167
Total	$114,684	$127,228	$131,526	$137,087	$129,468
Peak Demand (MW)	171	182		176	

(1) Revenues are exclusive of wholesale sales.
(2) Columns may not add to totals due to rounding.
Source: City of Palo Alto.

Service Area

Population. The service area of Palo Alto's electric system is coterminous with Palo Alto's city boundaries. Shown below is certain population data for Palo Alto, the County of Santa Clara and the State of California.

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CITY OF PALO ALTO, COUNTY OF SANTA CLARA,
STATE OF CALIFORNIA POPULATION
(1970-2010 as of April 1; 2011-2021 as of January 1)

Year	City of Palo Alto	County of Santa Clara	State of California
1970	56,040	1,065,313	19,971,069
1980	55,225	1,295,071	23,667,764
1990	55,900	1,497,577	29,760,021
2000	58,598	1,682,585	33,871,653
2010	64,403	1,781,642	37,253,956
2011	65,290	1,806,087	37,561,624
2012	66,202	1,834,926	37,924,661
2013	67,051	1,863,975	38,269,864
2014	67,403	1,887,079	38,556,731
2015	67,816	1,911,670	38,865,532
2016	68,393	1,928,438	39,103,587
2017	68,679	1,937,008	39,352,398
2018	68,482	1,943,579	39,519,535
2019	68,272	1,944,733	39,605,361
2020	68,145	1,945,166	39,648,938
2021	67,657	1,934,171	39,466,855

Sources: 1970-2010, as of April 1, based on historical U.S. Census population data compiled by the California State Department of Finance. 2011-2021, as of January 1, State of California, Department of Finance, E-4 Population Estimates for Cities, Counties and the State, with 2010 Census Benchmark. Sacramento, California, May 2019.

Employment. The main businesses in Palo Alto are manufacturing and industrial, but Palo Alto is also home to significant health care and education providers. There are numerous manufacturing plants producing electronic components, communications equipment, computer systems and similar products, and general items such as pharmaceutical and aerospace systems.

The ten largest employers in Palo Alto as of June 30, 2021 are shown in the following table.

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CITY OF PALO ALTO
LARGEST EMPLOYERS

Employer	Business	Number of Employees
Stanford Health Care	Health Care Delivery	5,500
Hewlett Packard Company	Computer Hardware and Software	5,000
Stanford University[(1)]	Education	4,060
Veteran's Affairs Palo Alto Health Care System	Health Care Delivery	3,900
Stanford Children's Health/Lucile Packard Children's Health	Health-Care Delivery	3,500
VMware Inc.	Software	3,500
SAP Labs Inc.	Software	3,500
Varian Medical Systems	Medical Devices and Software	3,300
Tesla Inc.	Technology	2,650
Palo Alto Medical Foundation	Health Care Delivery	2,200

(1) Stanford University number of employees was provided by the Stanford Office of Planning and includes only employees located in Palo Alto.

Source: City of Palo Alto.

The San Jose-Sunnyvale-Santa Clara Metropolitan Statistical Area, as defined by the State Employment Development Department, includes all cities within San Benito and Santa Clara Counties. According to the California Employment Development Department, the County of Santa Clara's unemployment rate was 4.0% for the year 2020.

The following table sets forth certain information regarding employment in the City of Palo Alto for the fiscal year 2016-2017 through 2020-2021.

CITY OF PALO ALTO
UNEMPLOYMENT RATES 2017 TO 2021

Fiscal Year	Unemployment Rate
2016-17	2.4%
2017-18	2.5
2018-19	2.1
2019-20	5.7
2020-21	3.2

Source: State Department of Employment Development as reflected in City of Palo Alto Annual Comprehensive Financial Report for the fiscal year ended June 30, 2021.

Assessed Valuation. The five-year history of assessed valuations in Palo Alto is as follows.

CITY OF PALO ALTO
TOTAL ASSESSED VALUATIONS
(Fiscal Years 2016-17 through 2020-21)

2016-17	2017-18	2018-19	2019-20	2020-21
$31,954,381	$34,434,739	$36,801,413	$39,285,460	$42,353,926

Source: County of Santa Clara's Assessor's Office.

Transportation. Palo Alto is served by freeways, interstate and state highways, bus service and trucking lines. Passenger rail transportation is provided by the Amtrak on a north/south commuter track. Air transportation is available at San Francisco International Airport, located approximately 25 miles to the north, and the San Jose International Airport which is approximately 15 miles from downtown Palo Alto.

Educational Facilities. Public education is provided in Palo Alto from kindergarten through high school. Palo Alto is also the location of Stanford University.

Forecast of Capital Expenditures

Palo Alto's five-year capital plan for electric distribution facilities contemplates capital expenditures in the following years and amounts:

CITY OF PALO ALTO
DEPARTMENT OF UTILITIES
ESTIMATED CAPITAL EXPENDITURES
(Dollar Amounts in Thousands)

Fiscal Year Ended June 30,				
2022	**2023**	**2024**	**2025**	**2026**
$31,726	$25,166	$21,700	$10,345	$10,750

Source: City of Palo Alto.

The capital expenditures are for infrastructure replacement and new customer connections; Palo Alto anticipates funding the majority of such costs from current year revenues. Since the 1960's Palo Alto has followed a policy of funding its capital improvements primarily from revenues rather than debt financing. $17 million of the five year capital expenditure total is allocated to the Smart Grid Technology project from 2022 through 2024. The Smart Grid project will be funded by the Electric Special Project Reserves.

Palo Alto does not currently plan to make further investment in new large-scale generation. Most of Palo Alto's anticipated energy deficits are expected to be met with renewable power purchase agreements, long-term and short-term market purchases, and customer site distributed generation. Palo Alto is in the initial phases of studying a transmission upgrade project.

Indebtedness; Joint Powers Agency Obligations

In October 2007, Palo Alto issued $1.5 million of 2007 Electric Utility Clean Renewable Energy Tax Credit Bonds ("CREBs") to finance Palo Alto's photovoltaic solar panel project. The bonds do not bear interest and are scheduled to be fully paid by December 2021. In lieu of receiving the periodic interest payments, bondholders are allowed annual federal income tax credits in an amount equal to a credit rate for such CREBs multiplied by the outstanding principal amount of the CREBs owned by the bondholders. As of June 30, 2021, the remaining outstanding principal balance of the CREBs was $100,000.Palo Alto has no outstanding revenue bonds or other direct debt payable from net revenues of the electric system.

As previously discussed, Palo Alto participates in two joint powers agencies, including NCPA and TANC. Obligations of Palo Alto under its agreements with respect to NCPA and TANC constitute operating expenses of the Palo Alto electric system payable prior to any of the payments required to be made on Palo Alto's utilities' revenue bonds or other obligations. Agreements with the joint powers agencies in which Palo Alto participates are on a "take-or-pay" basis, which requires payments to be made whether or not projects are completed or operable, and whether output from such projects is suspended, interrupted or terminated. These agreements contain "step-up" provisions obligating Palo Alto to pay a share of the obligations of a defaulting participant. Palo Alto'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.

CITY OF PALO ALTO
DEPARTMENT OF UTILITIES
OUTSTANDING DEBT OF JOINT POWERS AGENCIES
(Dollar Amounts in Millions)
(As of January 31, 2022)

	Outstanding Debt[1]	Palo Alto Participation[2]	Palo Alto Share of Outstanding Debt[1]
NCPA			
Geothermal Project	$ 10.8	0.00%[3]	$0.7[3]
Hydroelectric Project	223.3	22.92[4]	52.5[4]
TANC			
COTP	169.9	0.00[5]	6.8[5]
TOTAL	$404.0		$60.0

(1) Principal only. Does not include obligation for payment of interest on such debt.
(2) Participation based on actual debt service obligation. Participation obligation is subject to increase upon default of another project participant. Such increase shall not exceed, without written consent of a non-defaulting participant, an accumulated maximum of 25% of such non-defaulting participant's original participation.
(3) Participation share of 6.16% was permanently assigned to TID in October 1984. Palo Alto remains contractually liable for its share. See "– Power Supply Resources – Joint Powers Agency Resources – *NCPA*" above.
(4) Palo Alto's actual payments represent approximately 23.5% of outstanding debt service as a result of credit to non-participating members with respect to portion of debt obligation.
(5) Participation share of 4.00% was assigned to SMUD, TID and MID in August 2008. Palo Alto remains contractually obligated for its share. See "– Power Supply Resources – Joint Powers Agency Resources – *TANC California-Oregon Transmission Project*" above.
Source: City of Palo Alto.

A portion of the joint powers agency debt obligations are variable rate debt, liquidity support for which is provided through liquidity arrangements with banks. Unreimbursed draws under liquidity arrangements supporting joint powers agency variable rate debt obligations bear interest at a maximum rate substantially in excess of the current interest rates on such obligations. Moreover, in certain circumstances, the failure to reimburse draws on the liquidity agreements may result in the acceleration of scheduled payment of the principal of such variable rate joint powers agency obligations. To the extent a joint powers agency has entered into interest rate swap agreements for the purposes of substantially fixing the interest cost with respect to variable rate joint powers agency obligations, there is no guarantee that the floating rate payable to such joint powers agency pursuant to such interest rate swap agreements will match the variable interest rate on the associated variable rate joint powers agency debt obligations to which the respective interest rate swap agreement relates at all times or at any time. Under certain circumstances, the swap provider may be obligated to make payments to the joint powers agency under their respective interest rate swap agreement that is less than the interest due on the associated variable rate joint powers agency debt obligations to which such interest rate swap agreement relates. In such event, such insufficiency will be payable from the obligated joint powers agency members (a corresponding amount of which proportionate to its debt service obligations to such joint powers agency could be due from Palo Alto). In addition, under certain circumstances, each of the swap agreements is subject to early termination, in which event the joint powers agency could be obligated to make a termination payment to the applicable swap provider (a corresponding amount of which proportionate to its debt service obligations to such joint powers agency could be due from Palo Alto). The only currently outstanding interest rate swap agreement related to Palo Alto's variable rate joint powers agency debt obligations is the 2008 Series A Hydroelectric Swap which is expected to be terminated in connection with the issuance of the 2022 Bonds. See "PLAN OF REFUNDING" in the front part of this Official Statement.

Employees

Labor Relations. As of February 1, 2022 , 111 full-time equivalent ("FTE") staff were assigned to the electric system of the Palo Alto Department of Utilities. All full-time employees, excluding the Utility Director and Chief Operating Officer, are represented by the Utilities Management and Professional Association of Palo Alto ("UMPAPA") and Service Employees' International Union ("SEIU") Local 521. Matters pertaining to wages, benefits and working conditions are governed by a memorandum of understanding between the City of Palo Alto and SEIU. In December 2018, the City Council approved the first memorandum of understanding with UMPAPA that expired on June 30, 2019. The City Council subsequently approved an updated memorandum of understanding with UMPAPA that expires on June 30, 2022. The memorandum of understanding with SEIU expired on December 31, 2021. Until a successor contract is negotiated, the terms of the expired contract will continue to govern. Palo Alto's wage and fringe benefits are generally comparable to those offered by other local public agencies.

Pension Plans. Retirement benefits to City of Palo Alto employees, including those assigned to electric system, are provided through the Palo Alto's participation in 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. Copies of the CalPERS annual financial report may be obtained from the CalPERS Executive Office, 400 Q Street, Sacramento, California 95814.

Palo Alto's defined benefit pension plans, the Miscellaneous Plan and the Safety Plan of the Palo Alto, provide retirement and disability benefits, annual cost-of-living adjustments, and death benefits to plan members and beneficiaries for substantially all permanent Palo Alto employees. Benefit provisions under the plans are established by State statute and local government resolution. No employees assigned to the electric system participate in the Safety Plan.

Pension costs are funded by bi-weekly contributions to CalPERS by Palo Alto and contributions from employees. Active Miscellaneous Plan members hired prior to July 17, 2010 are required to contribute 8.00% of their annual covered salary, those member hired on or after July 17, 2010 are required to contribute 7.00% and those hired on or after January 1, 2013 are required to contribute 6.25% of their annual covered salary. The member contribution can be paid by the employee or by Palo Alto on the employee's behalf in accordance with applicable labor agreements. The required member contributions are currently paid by the employees. Palo Alto's employer contribution rate is determined annually by the actuary 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 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. Palo Alto is required to contribute the difference between the actuarially determined rate and the contribution rate of employees. The actuarial methods and assumptions used are those adopted by the CalPERS Board of Administration. The contribution requirements of the plan members are established by State statute and the employer contribution rates are established, and may be amended, by CalPERS.

In April 2017, Palo Alto established an Internal Revenue Code Section 115 irrevocable trust with the Public Agency Retirement Services ("PARS"). The Palo Alto City Council approved an initial deposit of $2.1 million in general fund proceeds into the general fund subaccount of Palo Alto's PARS Trust Account. The PARS Trust Account allows more control and flexibility in investment allocations compared to Palo Alto's portfolio which is restricted by State regulations to fixed income instructions. As of

December 31, 2021, Palo Alto reported the account balance of $37.7 million as restricted cash in general benefits, an internal service fund.

The table below sets forth the electric system's allocated share of Palo Alto's required contributions to the Miscellaneous Plan for the five fiscal years 2016-17 through 2020-21. The amount budgeted for the electric system's allocated share of Palo Alto's estimated required contributions to such plan for fiscal year 2021-22 is $5,783,964.

City of Palo Alto Miscellaneous Plan
(dollars in thousands)

Fiscal Year Ended June 30	Electric System Allocated Share	Total City Required Contribution Amount	Contributions as a % of Covered Payroll
2017	$2,961	$20,638	26.59%
2018	4,496	23,342	28.95
2019		25,423	30.79
2020		28,889	35.66
2021		32,782	37.60

Source: City of Palo Alto.

Palo Alto'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 Palo Alto's required contributions to CalPERS in future years. Accordingly, Palo Alto cannot provide any assurances that Palo Alto'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 assumptions used to determine the actuarial accrued liabilities may be found in Palo Alto's most recent audited financial statements which are available on Palo Alto's website at *http://www.cityofpaloalto.org.*

On December 21, 2016, the CalPERS Board of Administration voted to lower the pension plan's assumed rate of return for purposes of its actuarial valuations from 7.5% to 7.0% by 2020 (which reduction has been phased in over the period from fiscal year 2017-18 to 2019-20). The impact of each reduction in the rate of return will be phased in over five years, with the full impact realized in the 2024-25 fiscal year. CalPERS has estimated that with a reduction in the rate of return to 7.0%, most employers could expect a 1% to 3% increase in the percentage of payroll contribution for the normal cost for miscellaneous plans. In addition, CalPERS has estimated that employers could expect gradual increases in their unfunded accrued liability payment, reaching an approximate increase in such payment (relative to the unfunded accrued liability payments projected in the June 30, 2015 valuation report) of 30% to 40% by fiscal year 2024-25 for miscellaneous plans. As a result, required contributions of employers, including Palo Alto, toward unfunded accrued liabilities, and as a percentage of payroll for normal costs, are expected to increase.

The announcement on July 12, 2021 that CalPERS achieved a preliminary investment return of 21.3% for the period from July 1, 2020 through June 30, 2021 caused the CalPERS Board of Administration to lower CalPERS' discount rate from 7.0% to 6.8% on November 15, 2021 in accordance with a risk mitigation policy that was adopted in 2015, which calls for the discount rate to be lowered if returns exceed the then-current discount rate by two or more percentage points. Lowering the discount rate generally means that employers which contract with CalPERS to administer their pension plans will see increases in their normal costs and unfunded actuarial liabilities.

Effective for the fiscal year ended June 30, 2015, Palo Alto adopted Governmental Accounting Standards Board ("GASB") Statement No. 68 ("GASB No. 68"), affecting the reporting of pension liabilities for accounting purposes. Under GASB No. 68, Palo Alto 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 Net Pension Liability of the Miscellaneous Plan as of June 30, 2016 through June 30, 2020, as reported in Palo Alto's audited financial statements for the fiscal year ended June 30, 2021. The electric system's allocable share of Palo Alto's net pension liability was not separately determined.

	City of Palo Alto Miscellaneous Plan (dollars in thousands)		
Measurement Date[1] (June 30)	**Net Pension Liability**	**Net Position as a % of Total Pension Liability**	**Net Pension Liability as a % of Covered Payroll**
2016	$244,237	65.79%	331.29%
2017	267,805	65.70	345.08
2018	264,661	67.38	328.23
2019	275,164	67.59	333.24
2020	290,272	67.18	358.29

(1) Measured using prior fiscal year annual actuarial valuation rolled forward to measurement date using standard update procedures.
Source: City of Palo Alto.

As of the June 30, 2020 measurement date, the total pension liability for the Miscellaneous Plan for the City of Palo Alto was $849,004 and the plan fiduciary net position was $594,063, resulting in a city-wide Miscellaneous Plan net pension liability of $290,272. In the June 30, 2019 actuarial valuation utilized for measuring the pension liability as of the June 30, 2020 measurement date, the Entry Age Normal Actuarial Cost Method was used. The actuarial valuation assumptions used for determining pension liabilities included (a) a 7.15% discount rate; (b) projected salary increases that vary based on age and type of service; and (c) an inflation rate of 2.50% per year.

Retiree Health Benefits. Palo Alto participates in the California Public Employees Medical and Health Care Act to provide certain health care benefits for retired employees, including employees of the electric system (the "OPEB Plan"). In fiscal year 2007-08, Palo Alto elected to participate in an irrevocable trust (the "Trust Fund") to provide a funding mechanism for its OPEB liability. The Trust Fund, California Employers' Retirees Benefit Trust, is administered by CalPERS and managed by a separately appointed board, which is not under control of the City Council. Palo Alto's policy is to prefund these OPEB benefits by accumulating assets in the Trust Fund pursuant to City Council Resolution. The OPEB Plan annual contributions to the Trust Fund are based on actuarial valuations. Under the OPEB Plan, employees who retire directly from the City of Palo Alto are eligible for benefits if they retire on or after age 50 with 5 years of service and are receiving a monthly pension from CalPERS.

Effective for fiscal year 2017-18, Palo Alto 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 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 affect funding requirements.

The table below sets forth certain information regarding the electric system's allocated share of Palo Alto's annual contributions to the OPEB Plan trust for the four fiscal years ended June 30, 2018 through June 30, 2021, and the relation of Palo Alto's contributions to the actuarially determined contribution amount for such fiscal year. The amount budgeted for the electric system's share of OPEB Plan contributions for fiscal year 2021-22 is $1,558,060.

City of Palo Alto OPEB Plan
(dollars in thousands)

Fiscal Year Ended June 30	Contribution Funded by Electric System	Total City Contribution	Actuarially Determined Contribution Amount	Contribution Deficiency (Excess) to Actuarially Determined Contribution
2018	$560	$21,349	$16,938	$(4,411)
2019		15,997	15,997	--
2020		16,475	16,482	7
2021		14,592	14,566	(26)

Source: City of Palo Alto.

Pursuant to GASB No. 75, for the fiscal year ended June 30, 2021, Palo Alto reported a net OPEB liability of approximately $124,798,000 (reflecting a total OPEB liability of $251,293,000 and a plan fiduciary net position of $126,495,000 for the OPEB Plan). The net OPEB liability as a percentage of covered-employee payroll was 99.30%. The OPEB Plan Net Position as a percentage of Palo Alto's total OPEB liability was 50.34%. The net OPEB liability was measured as of June 30, 2020, using an annual actuarial valuation as of June 30, 2019, based on actuarial methods and assumptions. The actuarial assumptions used include: (a) a 6.75% discount rate; (b) a 2.75% inflation rate; (c) payroll growth of 3.00%; (d) a 6.75% investment rate of return; and (e) post-retirement benefit cost increases of 6.30% for 2021, decreasing to 4.00% for 2076 and later for Medicare plan premiums, and 7.25% for 2021, decreasing to 4.00% for 2076 and later for Non-Medicare premiums.

Additional information regarding the City of Palo Alto's retirement plans and other post-employment benefits can be found in Palo Alto's annual comprehensive financial reports, which may be obtained at *http://www.cityofpaloalto.org*.

Insurance

Palo Alto is self-insured up to $1 million and is a member of the Authority for California Cities Excess Liability ("ACCEL") risk pool. ACCEL is a joint powers authority that includes 13 members from medium-sized cities self-funding for catastrophic losses. Palo Alto shares risk within this pool up to $4 million and through the pool, purchases commercial excess insurance limits up to $200 million. In addition, Palo Alto maintains property insurance including loss or damage to Palo Alto electric system property.

Litigation

There is no action, suit or proceeding known to be pending or threatened, restraining or enjoining Palo Alto in the execution or delivery of, or in any way contesting or affecting the validity of any proceedings of Palo Alto taken with respect to, the Third Phase Agreement.

There is no litigation pending, or to the knowledge of Palo Alto, threatened, questioning the existence of Palo Alto, or the title of the officers of Palo Alto to their respective offices. As of the date of this Official Statement, there is no litigation pending, or to the knowledge of Palo Alto, threatened, questioning or affecting in any material respect the financial condition of Palo Alto's electric utility system.

As described below, litigation has been filed challenging the Palo Alto utilities' transfers to the General Fund:

Green v. City of Palo Alto. Through annual equity transfers, Palo Alto transfers a portion of the earnings of its gas and electric utilities to its General Fund each year, pursuant to a voter-approved charter provision authorizing it to do so. In October 2016, plaintiff Miriam Green ("Green") filed a class action lawsuit against Palo Alto challenging Palo Alto's equity transfers and electric rates, under Proposition 26. In the fiscal year ended June 30, 2021, these transfers amounted to $[19.6] million ($[12.9] million electric and $[6.7] million gas) and in the fiscal year ended June 30, 2020, the transfers amounted to $[18.7] million ($[12] million electric and $[6.7] million gas). *{to be updated}* In this respect, Palo Alto is similar to other municipal power utilities (and four municipal gas utilities in California), which make annual general fund transfers on various theories.

On January 2, 2020, the Santa Clara Superior Court found the City's electric rates did not violate Proposition 26; a complete victory for the City on the electric side of the case. The court found that because the City had sufficient non-rate revenue to fund the electric-to-general fund transfer, the City's electric rates for the time period covered by the lawsuit did not exceed the reasonable cost of providing electric service, and therefore did not constitute a tax requiring voter approval.

The trial court also found that the City's gas rates for the relevant period *were* taxes, since the City lacked sufficient non-rate revenue to cover the gas to general fund transfer. On September 20, 2021, the City Council voted to appeal the trial court's decision on the City's gas rates. Since then, the parties have engaged in preliminary settlement discussions and have opted to pursue mediation as to the plaintiff's gas claims. A mediation date has not yet been assigned by the court. The Green litigation has not and will not in the future have a material financial impact on Palo Alto's Electric Fund.

Lawsuits and other claims filed against Palo Alto as it relates to its Department of Utilities' electric system and operations arise in the ordinary course and scope of Palo Alto's municipal utility business and are largely covered by Palo Alto's self-insurance program. In the opinion of Palo Alto's management and attorneys, these lawsuits and other claims will not have a material adverse effect upon Palo Alto's electric system and operations.

Palo Alto's Operations Since Industry Restructuring

Electric System Policies. In March 1997, the City Council of Palo Alto approved three electric utility policies relating to customer choice, stranded cost recovery and marketing beyond Palo Alto borders. Palo Alto undertook a number of actions in order to implement those policies. Direct access (discussed below) was offered to large commercial and industrial customers; however, none of them exercised the option. Given the lack of interest in the community for direct access in combination with the instability of energy markets in 2001 and CPUC actions relating to direct access, direct access was suspended by the City Council effective August 1, 2001. There are no plans to re-implement direct access at this time.

AB 1890, adopted in 1996, provided for the deregulation of California's electric industry effective January 1, 1998. A key element of deregulation was the provision for "direct access", which would allow electric customers to choose their electric commodity supplier. Palo Alto, along with other California utilities, was faced with the prospect of losing customers and load to direct access and having made significant investments in generation assets purchased or built to serve these customers. In response to such risk, PG&E and certain other investor- and municipally-owned utilities established stranded cost surcharges to collect funds from ratepayers to cover the amount that these uneconomic assets were projected to cost above their market value in the future (*i.e.*, "stranded cost").

Electric Special Project Reserve (formerly the Calaveras Reserve). In 1983, the City Council established the Calaveras Reserve in the Electric Fund to help defray a portion of the annual debt service costs associated with the NCPA Calaveras Hydroelectric Project, which was put in service at that time. As originally established, the Calaveras Reserve policy did not provide for a target balance and depletion of the reserve was anticipated by 2002.

In 1996, the City Council changed the purpose of the Calaveras Reserve and authorized collections from electric ratepayers to cover stranded cost. In addition, the City Council approved a new policy linking the reserve balance to an amount sufficient to cover other potential stranded costs. The assets identified as stranded at that time included the Seattle City Light Exchange contract (terminated in May 2018), the Calaveras Hydroelectric Project and the COTP.

In 1997, the City Council revised the reserve target level to cover above-market, or "stranded," costs to $93 million by December 31, 2001 to be collected from a stranded cost surcharge imposed on electric rates. When the Calaveras Reserve balance reached $71 million in 1999, stranded costs were deemed fully collected. At that time, Council authorized the cessation of the collection of the stranded cost surcharge and established the Calaveras Reserve Target and Guidelines with a schedule to drawdown the funds and manage electric rates through transfers from the Calaveras Reserve to the Electric Supply Rate Stabilization Reserve (E-SRSR) through the end of fiscal year 2032-33, when the Calaveras Reserve would be exhausted.

In 2001, the California electric industry faced an energy crisis triggering wholesale power price spikes and rolling blackouts throughout the State. The crisis was blamed on poor deregulation market design and market manipulation by energy suppliers. As a result, direct access was suspended in California for the investor-owned utilities (although it was subsequently phased in for non-residential end-use customers of the investor-owned utilities pursuant to Senate Bill 695, adopted in 2009) and subsequently, Palo Alto suspended its direct access program. Further, as a result of changing market conditions and the assignment of certain electric assets, the estimate of the City's stranded cost is lower now than when stranded cost collections stopped in 1999. Since then, electric market prices have increased significantly, reducing the stranded cost associated with the Calaveras Hydroelectric Project.

On June 15, 2009, the City Council adopted new guidelines to manage the Calaveras Reserve which required an annual calculation of short-term stranded costs during the annual budget process for the upcoming budget year(s) and set the minimum transfer from the Calaveras Reserve to the Electric Supply Operating Budget equal to this amount. The revised guidelines also called for an annual calculation of long-term stranded cost and identification of any excess funds in the Calaveras Reserve available to fund projects to the benefit of electric ratepayers.

On November 1, 2011, the City Council renamed the Calaveras Reserve as the Electric Special Project Reserve ("ESP") and approved a new policy direction and guidelines for use of funds. On May 18, 2015, the City Council updated the guidelines to extend the deadlines to commit funds and close the ESP Reserve, as follows:

- The purpose of the ESP Reserve is to fund projects that benefit electric ratepayers;
- ESP Reserve funds are to be used for projects of significant impact;
- Projects proposed for funding must demonstrate a need and/or value to electric ratepayers. The projects must have verifiable value and not be speculative, or risky in nature;
- Projects proposed for funding must be substantial in size, requiring funding of at least $1 million;
- Set a goal to commit funds by end of fiscal year 2016-17; and

- Any uncommitted funds remaining at the end of fiscal year 2021-22 will be transferred to the Electric Supply Operation Reserve and the ESP Reserve will be closed.

As of December 2021, the ESP Reserve funds have not been fully committed; however, staff is evaluating suitable large projects such as advanced metering infrastructure which could increase utility resiliency. The approximate balance of the ESP Reserve as of June 30 for the five fiscal years 2016-17 through 2020-21 is set forth below:

	2016-17	**2017-18[(1)]**	**2018-19**	**2019-20**	**2020-21**
Balance	$51,838,000	$41,665,000	$41,700,000	$46,700,000	$46,700,000

Source: City of Palo Alto Audited Financial Statements for fiscal years 2013-14 through 2017-18.

(1) In fiscal year 2017-18, the Palo Alto City Council approved a $10 million loan from the ESP Reserve to keep the Electric Distribution Operations Reserve above the minimum reserve guidelines. The loan is expected to be repaid to the ESP Reserve within five years. See "–*Operations Reserve*" below.

Rate Stabilization Reserve. In June 1998, the City Council approved staff's recommendation to unbundle the Electric and Gas Rate Stabilization Reserves ("RSR"). The RSR was originally created to cover a number of unforeseen contingencies, including the need to supplement rates which cover distribution expenses, and commodity supply costs. The City Council has approved a set of guidelines for the RSR based on a forecast of contingencies to be covered. In December 2003 and again in January 2007, the City Council updated the reserve guidelines taking into account, among other aspects, the increased cost volatility due to the electric portfolio cost exposure to hydroelectric production uncertainties that arose in 2005 with the then-new Western Base Resource Contract. In June 2014, the City Council approved updated Reserves Management Practices, and existing reserves were separated for more specific purposes. The RSR is now are used to manage the trajectory of future rate increases, with the Operations Reserve being used to manage normal variations in the costs of providing electric service and as a reserve for contingencies. As of June 30, 2021, the balance of RSR was $51.3 million.

Operations Reserve. In June 2014, the City Council approved updated Reserves Management Practices. New Electric Supply Fund and Electric Distribution Fund Operations Reserves were created, and are used to manage normal variations in the costs of providing electric service and as a reserve for contingencies. The City Council approved a set of guidelines for the minimum and maximum level of reserves to be held, as well as policies should reserves fall outside of those ranges. As of June 30, 2021, the balance of the Supply Operations and Distribution Operations Reserves were $19.9 and $10.0 million, respectively. [The Supply Operations Reserve amount is below the City Council guidelines for the minimum level of reserves to be held, but the City Council approved transfers in fiscal year 2018 to raise the balance of such reserves above the guidelines for the minimum level.] ***{to be updated}***

Hydro Stabilization Reserve. In accordance with the City's updated Reserves Management Practices approved in June 2014, supply cost savings and surplus energy sales revenue associated with higher than average generation from hydroelectric resources may be added to the Electric Supply Fund's Hydro Stabilization Reserve by action of the City Council and held to offset higher commodity supply costs during years of lower than average generation. Withdrawal of funds from the Hydro Stabilization Reserve requires action by the City Council. As of June 30, 2021, the balance of the Hydro Stabilization Reserve was $15.4 million.

Public Benefits Reserve. In June 1998, the City Council of Palo Alto approved the Public Benefits Reserve to be created for the purpose of establishing a separate reserve from the Electric Fund. The revenue collected for the Public Benefit programs that are not spent are deposited into this reserve for future use. The balance of the Public Benefits Reserve at June 30, 2021 was $3.0.

Unbundled Electric Rates. In June 1997, Palo Alto became the first electric utility in California to unbundle its electric rates on customers' bills. Palo Alto's unbundled electric rates were initially comprised of the following four components: (i) a power supply charge, (ii) a distribution charge, (iii) a transition cost recovery charge and (iv) a public benefits charge. On July 1, 1999, the transition cost recovery charge was discontinued. The distribution charge and public benefits charge are non-bypassable charges and therefore are paid to Palo Alto by the customer, regardless of energy supplier.

Significant Accounting Policies

Palo Alto's most recent Annual Financial Report for the fiscal year ended June 30, 2021 has been audited by Macias Gini & O'Connell LLP, Walnut Creek, California, in accordance with generally accepted auditing standards, and contains opinions that the financial statements present fairly, in all material respects, the respective financial position of the various funds maintained by Palo Alto. The reports include certain notes to the financial statements which are not described below. Such notes constitute an integral part of the audited financial statements. Copies of these reports are available on request from the Administrative Services Department, City of Palo Alto, 250 Hamilton Avenue, Palo Alto, California 94301 and are available on-line at *https://www.cityofpaloalto.org/gov/depts/asd/ reporting.asp*. Governmental accounting systems are organized and operated on a fund basis. A fund is defined as an independent fiscal and accounting entity with a self-balancing set of accounts recording cash and other financial resources, together with all related liabilities and residual equities or balances, and changes therein. Funds are segregated for the purpose of carrying on specific activities or attaining certain objectives in accordance with special regulations, restrictions or limitations.

The Palo Alto electric system is accounted for as an enterprise fund. Enterprise funds are used to account for operations (i) that are financed and operated in a manner similar to private business enterprises (where the intent of the governing body is that the costs (expenses, including depreciation) of providing goods or services to the general public on a continuing basis be financed or recovered primarily through user charges) or (ii) where the governing body has decided that periodic determination of revenues earned, expenses incurred and/or net income is appropriate for capital maintenance, public policy, management control, accountability or other purposes.

Condensed Operating Results and Selected Balance Sheet Information

The following table sets forth summaries of income and selected balance sheet information of Palo Alto's electric funds for the five fiscal years 2016-17 through 2020-21. The information for the fiscal years ended June 30, 2017 through June 30, 2021 was prepared by Palo Alto on the basis of its audited financial statements for such years.

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CITY OF PALO ALTO
DEPARTMENT OF UTILITIES
ELECTRIC AND FIBER OPTICS FUNDS
CONDENSED OPERATING RESULTS AND SELECTED BALANCE SHEET INFORMATION[1]
(Dollar Amounts in Thousands)

	Fiscal Year ended June 30,				
	2017	**2018**	**2019**	**2020**	**2021**
Summary of Income:					
Operating Revenues	$137,543	$ 154,142	$ 163,514	$ 169,389	$ 162,240
Operating Expenses[2]	(119,568)	(136,902)	(130,881)	(136,717)	(148,850)
Operating Income	17,975	17,240	32,633	36,672	13,390
Other Income[3]	(9,224)	(8,477)	(3,430)	(2,631)	(6,819)
Loss on Disposal of Fixed Assets	(116)	(26)	(103)	(87)	(70)
Transfers in	2,679	3,465	3,335	2,582	2,582
Transfers out[4]	(12,543)	(13,448)	(13,470)	(13,906)	(13,945)
Net Income	$ (1,229)	$ (1,246)	$ 18,965	$ 18,630	$ (4,862)
Selected Balance Sheet Information:					
Net Property Plant and Equipment	$190,930	$193,313	$ 200,749	$ 205,613	$ 209,851
Unrestricted	76,643	58,286	69,815	83,581	74,481
Total Net Assets	$ 267,573	$ 251,599	$ 270,564	$ 289,914	$ 284,332

(1) A schedule reflecting the breakdown of the financial results for each of Palo Alto's proprietary funds for the Fiscal Year ended June 30, 2021 can be found in the Annual Report, which has been incorporated herein by reference. See "– Introduction" above.
(2) Includes purchased power costs and payments to NCPA and TANC. Also includes depreciation in the amount (in thousands) of $7,733 in fiscal year 2017, $8,432 in fiscal year 2018, $2,808 in fiscal year 2019, $3,002 in fiscal year 2020 and $3,127 in fiscal year 2021.
(3) The negative "Other Income" consists of debt service Palo Alto paid on NCPA bonds and investment earnings due to recording of market value gains.
(4) Composed primarily of transfers to Palo Alto general fund for costs incurred for the benefit of the Palo Alto utility system, transfers to fund retiree medical benefits and transfers to the capital projects fund.
Source: City of Palo Alto.

CITY OF ROSEVILLE

Introduction

The City of Roseville ("Roseville" or the "City") is a charter city in the State of California. Roseville is located in Placer County, in California's Sacramento Valley near the foothills of the Sierra Nevada mountain range, about 16 miles northeast of Sacramento and 110 miles east of San Francisco. Roseville, with a population estimated to be approximately 146,875 at January 1, 2021, is the largest city in Placer County, as well as the residential and industrial center of the county.

Roseville, through its electric system (the "Electric System"), has been providing electrical power to its residents, businesses, and Roseville's street and traffic lighting systems since 1912. In 1956, Roseville entered into a contract with the federal Bureau of Reclamation for 54 megawatts ("MW") (a megawatt equals 1 million watts) of electric capacity from the Central Valley Project (the "CVP"), which consists of a system of dams, reservoirs and hydroelectric power plants within central and northern California (the contract is currently administered through the Western Area Power Administration ("Western")). In the early 1970s, Roseville's demand for electricity exceeded the Western resource allocation. To help meet this additional need, in 1968 Roseville became a charter member in NCPA. Roseville participates in several resources developed by NCPA, including its geothermal, steam-injected gas turbine, and hydroelectric projects (including the Project). In October of 2007, Roseville completed construction of a 160 MW natural gas-fired combined cycle power plant (the "Roseville Energy Park" or "REP"). REP was built as a reliable, economic alternative to bulk power purchases. REP has a base operating capacity of 120 MW with the ability to peak-fire up to 160 MW. On September 1, 2010, Roseville completed the purchase from NCPA, and assumed full title and ownership, of two of the five 24 MW simple cycle combustion turbines originally part of the NCPA Combustion Turbine Project Number One (for a total of 48 MW of capacity), which are connected to the Roseville electric distribution system (and now referred to as "Roseville Power Plant 2" or "RPP2") to meet reserve and capacity requirements.

Roseville's Electric System is under the supervision of the Roseville City Council. A seven-member Roseville Public Utilities Commission serves as an advisory board to the City Council on matters relating to all utilities owned and operated by the City. The City Council appoints all seven members of the Roseville Public Utilities Commission. The Electric Utility Director oversees operations of the electric utility and reports to the Assistant City Manager.

Only the revenues of the Roseville Electric System will be available to pay amounts owed by Roseville under the Third Phase Agreement.

The Roseville electric department's main office is located at 2090 Hilltop Circle, Roseville, California 95747, (916) 797-6937. For more information about Roseville and its Electric System, contact Daniel Beans, Electric Utility Director, at the above address and telephone number. A copy of the most recent annual comprehensive financial report of the City of Roseville (the "Annual Report") is available on Roseville's website at *https://www.roseville.ca.us/* and on the Municipal Securities Rulemaking Board's Electronic Municipal Market Access system at *http://emma.msrb.org/*. The Annual Report is incorporated herein by this reference. However, the information presented on such website or referenced therein other than the Annual Report is not part of this Official Statement and is not incorporated by reference herein.

Service Area, Customer Base and Demand

Service Area. The Roseville Electric System serves an area of approximately 43 square miles, virtually coterminous with the City's borders. As of June 30, 2021, the Electric System served an estimated 63,608 customers.

Customer Base. From Fiscal Year 2016-17 to Fiscal Year 2020-21, the Electric System's customer base (average annual number of customers) increased by nearly 9.0%. Residential housing units in Roseville total approximately 57,155, with additional new development underway. There are nearly 11,000 business within the City. In Fiscal Year 2020-21, 30 new construction commercial building permits were issued, representing approximately 602,963 square feet of commercial space.

Shown below is certain population data for the City of Roseville, the County of Placer and the State of California:

CITY OF ROSEVILLE, COUNTY OF PLACER,
STATE OF CALIFORNIA POPULATION
(1970-2010 as of April 1; 2011-2021 as of January 1)

	City of Roseville	County of Placer	State of California
1970	18,221	77,632	19,971,069
1980	24,347	117,247	23,667,764
1990	44,685	172,796	29,760,021
2000	79,921	248,399	33,871,653
2010	118,788	348,432	37,253,956
2011	121,290	354,247	37,561,624
2012	123,686	359,648	37,924,661
2013	126,310	363,837	38,269,864
2014	128,327	368,059	38,556,731
2015	129,730	371,234	38,865,532
2016	132,627	376,307	39,103,587
2017	135,300	383,258	39,352,398
2018	137,824	388,872	39,519,535
2019	141,097	395,345	39,605,361
2020	143,493	399,015	39,648,938
2021	146,875	404,994	39,466,855

Source: 1970-2010, as of April 1, based on historical U.S. Census population data compiled by the California State Department of Finance. 2011-2021, as of January 1, State of California, Department of Finance, E-4 Population Estimates for Cities, Counties and the State, with 2010 Census Benchmark. Sacramento, California, May 2021.

The largest employers in Roseville as of June 30, 2021 are set forth in the table on the following page:

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CITY OF ROSEVILLE
LARGEST EMPLOYERS

Employer	Business	Number of Employees
The Permanente Medical Group & Foundation Group	Health Care	5,200
Sutter Roseville Medical Center	Health Care	2,202
City of Roseville	Government	1,896
Roseville Joint Union High School District	Education	1,626
Adventist Health	Health Care	1,320
Union Pacific Railroad	Railroad	1,150
Roseville City School District	Education	1,133
PRIDE Industries	Employment Service	1,062
Top Golf	Entertainment	450
Hewlett-Packer	Technology	100

Source: City of Roseville Audited Comprehensive Financial Report; information from Roseville Chamber of Commerce and self-reported by employers.

Historical Customers Sales and Peak Demand. The average number of customers, electricity sales measured in megawatt hours ("MWh") and in revenues, and peak demand during the past five Fiscal Years, is listed below.

CITY OF ROSEVILLE
ELECTRIC SYSTEM
CUSTOMERS, SALES, REVENUES AND PEAK DEMAND [(1)]

	2017	2018	2019	2020	2021
Number of Customers:[(2)]					
Residential	51,638	52,789	53,868	54,687	56,549
Commercial	6,759	6,812	6,884	6,975	7,059
Total	58,397	59,601	60,752	61,662	63,608
MWh Sales					
Residential	439,598	454,795	441,823	458,207	502,808
Commercial	737,843	728,497	705,575	666,157	656,237
Total MWh Sales	1,177,441	1,183,292	1,147,398	1,124,364	1,159,045
Revenues ($ in 000s):					
Residential	$ 68,543	$ 70,803	$ 69,551	$ 71,499	$78,475
Commercial	93,011	91,495	89,727	84,190	84,172
Total Revenues from Sale of Energy	$161,554	$162,298	$159,278	$155,689	162,647
Peak Demand (MW)	355	354	340	334	341

(1) Revenues listed are as billed. For realized revenues, see the table under "Historical Revenues, Expenses and Debt Service Coverage" below.
(2) Customer counts reported as fiscal year average annual values.
Note: Totals may not add due to rounding.
Source: City of Roseville.

Ten Largest Customers

As of June 30, 2021, the ten largest customers of Roseville's Electric System by usage accounted for an estimated 22% of total kWh sales and 18% of total Electric System revenues. The largest customer accounted for an estimated 6.5% of total kWh sales and 5% of total Electric System revenues. The smallest of the ten largest customers accounted for an estimated 0.6% of total kWh sales and 0.5% of total Electric System revenues.

Sources of Power Supply

General

Roseville has a diverse portfolio of resources that includes large hydroelectric, geothermal, natural gas, system power contracts, and additional contracts for renewable energy. In addition, Roseville purchases its incremental needs through open market purchases. Roseville owns and operates the Roseville Energy Park and the two units constructed under NCPA Combustion Turbine Project Number One (subsequently renamed Roseville Power Plant 2) connected to the Roseville electric distribution system. Roseville has a long-term contract with Western for a share of the CVP net generation and entitlements to the output of several NCPA projects, including the Project.

The table on the following page provides an estimated summary of Roseville's sources of power supply for Fiscal Year 2020-21.

CITY OF ROSEVILLE
ELECTRIC SYSTEM
SOURCES OF POWER SUPPLY
Fiscal Year 2020-21

Source	Type	Capacity Available (MW)(1)	Actual Energy (GWh)(2)	% of Total
Generation:				
Roseville Energy Park	Natural Gas	155	383	32%
Roseville Power Plant 2	Natural Gas	48	3	0
Purchased Power:				
Western	Hydro	56	97	8
NCPA				
Geothermal Project	Geothermal	8	60	5
Hydroelectric Project	Hydro	30	25	2
Steam Injected Gas Turbine(3)	Natural Gas	18	17	1
Market Purchases:		79		
Renewable Purchases	Various	N/A	156	13
Non-Renewable Purchases	Various	N/A	461	38
TOTAL*		394	1,202	100%
Peak Demand (MW)		341		
Capacity Reserve Percent(4)		14%		

(1) Capacity in MW and available for system peak August 18, 2020.
(2) One gigawatt hour (GWh) equals 1 million kilowatt hours (kWh).
(3) Referred to as Unit One or the Capital Facilities Project in the front part of this Official Statement.
(4) Capacity includes resources and contracts for long-term and seasonable purchases. Capacity reserve planning target is 15% of the forecasted peak. Actual peak exceeded forecasted peak (333 MW).
* Numbers may not total due to rounding.

Source: City of Roseville

Roseville Energy Park

Roseville Energy Park ("REP"), is a 120 MW base load combined cycle, natural gas fueled power plant with duct firing capability up to 160 MW. The REP is located in the City of Roseville and is directly connected to Roseville's distribution system. REP is comprised of two Siemens SGT 800 combustion turbine units and a Siemens STG 900 steam turbine. The plant has been in commercial operation since October 2007 and is owned and operated by Roseville.

Roseville Power Plant 2

The Roseville Power Plant 2 consists of two 24 MW simple cycle combustion turbines ("CT1" and "CT2"), for a total of 48 MW of capacity. These units were previously part of the NCPA Combustion Turbine Project Number One in which Roseville was a participant. See "OTHER NCPA PROJECTS – Combustion Turbine Project Number One" in the front part of this Official Statement. On September 1, 2010, Roseville took ownership of the two units which provide peaking capacity and reserves for Roseville.

Western Area Power Administration

Roseville has various long-term contracts with Western that provide energy, interconnection, and transmission services. Roseville has a 4.85333% share of the net output of the CVP, which provides varying amounts of capacity and energy depending upon hydrologic conditions. The output is reduced by Western's project use, first preference customer allocations, environmental, and control area obligations. Roseville is directly connected to Western's transmission system and acquires reserves under contract that include regulation and frequency response and operational reserves. The current term of the power supply contract extends through December 31, 2024. Roseville and Western have negotiated a new contract that begins January 1, 2025. The new 2025 Base Resource contract will includes all the same services. The new 2025 Base Resource contract has a 30-year term with options for Roseville to exit every five years. It is anticipated Roseville will lose approximately 2% of its current share under the new 2025 Base Resource contract, making the new allocation 4.75627% in 2025.

Joint Powers Agency Resources

NCPA. In addition to generating and purchasing power from other sources, Roseville is a participant in a number of NCPA projects. Roseville has a 12.00% entitlement share in the NCPA Hydroelectric Project, a 36.50% entitlement share in the NCPA Capital Facilities Project (also referred to as the Unit One or the Combustion Turbine Project Number Two), and a 7.88% entitlement share in the NCPA Geothermal Project. For a description of such resources, see "THE HYDROELECTRIC PROJECT" and "OTHER NCPA PROJECTS" in the front part of this Official Statement. For each of these generation projects in which Roseville participates, Roseville is obligated to pay on an unconditional take-or-pay basis, as an operating expense of its electric system, its entitlement share of the debt service on NCPA bonds issued for the project as well as its share of the operation and maintenance expenses of the project. See also "– Indebtedness; Joint Powers Agency Obligations" below.

In order to meet certain obligations required of NCPA to secure transmission and other support services for the NCPA Geothermal Project, NCPA and its transmission project participants (including Roseville) undertook the "Geysers Transmission Project," which includes (a) an ownership interest in PG&E's 230 kilovolt ("kV;" 1 kilovolt equals 1,000 volts) line from Castle Rock Junction in Sonoma County to the Lakeville Substation, (b) additional firm transmission rights in this line, and (c) a Central Dispatch Center (see "Dispatch and Scheduling" below). Roseville is entitled to a 14.18% share of the Geysers Transmission Project transfer capability, and is responsible for 14.18% of the costs of such project. For a description of the Geysers Transmission Project, see "OTHER NCPA PROJECTS" in the front part of this Official Statement.

Renewable Purchases

With the passage of California Senate Bill X1-2, the California Renewable Energy Resources Act ("SBX1-2"), California Senate Bill 350, the Clean Energy and Pollution Reduction Act of 2015 ("SB350"), and California Senate Bill 100, the 100 Percent Clean Energy Act of 2018 ("SB 100"), Roseville must comply with the State's renewable energy targets to achieve renewable energy procurement of 33% by 2020, 50% by 2025, and 60% by 2030. Roseville has an additional incentive to enter into long-term contracts, as certain contracts at least ten years in duration have the ability to carry forward renewable energy credits to be used to meet future compliance periods. Starting in 2020, 65% of RPS procurement must be derived from long-term contracts of 10 or more years. Roseville satisfied the RPS target for Compliance Period 1 (from 2011 through 2013), with approximately 20% renewable energy procured, as well as Compliance Period 2 (from 2014 through 2016), with approximately 25% renewable energy procured. Roseville also satisfied the RPS target for Compliance Period 3 (2017-2020), reaching the 33% target for serving its retail energy load from renewable energy resources by 2020. Roseville's current RPS contracts are forecasted to fulfill compliance requirements under current law through 2024, including contracts with Silicon Valley Power, Powerex Corporation, Avangrid Renewables, Lost Hills Solar and Blackwell Solar, as well as grandfathered resources including geothermal and small hydroelectric projects. See also "CERTAIN FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY – State Legislation and Regulatory Proceedings – *California Renewables Portfolio Standard*" in the front part of this Official Statement for more information on SBX1-2, SB 350 and SB 100.

Open Market Term Purchase and Sale Agreements

Roseville enters into various fixed-price purchase or sale contracts on the open market at various times to meet its power supply requirements and hedge its portfolio costs consistent with its risk management policies. Purchases include transactions to hedge natural gas and electricity, physically or financially, over various tenors authorized in Roseville's Trading Authority Policy. Electricity and gas products are generally purchased or sold on a seasonal or annual basis, to comply with Roseville's Energy Hedge Policy (described below). Roseville transacts through a competitive bid process with a number of counterparties in line with its Credit Risk Policy. See "– Power Supply Risk Management" below.

Future Power Supply Resources

In addition to the above supply sources, Roseville expects that it will obtain additional resources from market purchases or investment in generation facilities, either independently, through NCPA or through other agencies. In accordance with current State law, Roseville expects that future energy purchases will increasingly be made from renewable energy sources. See "– Energy Efficiency and Conservation" below. See also "CERTAIN FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY – State Legislation and Regulatory Proceedings" in the front part of this Official Statement.

Power Supply Risk Management

The Electric System's risk management strategies and procedures are monitored by a risk oversight committee ("ROC") established by Roseville. The ROC meets on a regular basis and includes two members of the City Council, two members of the Roseville Public Utilities Commission, the City Manager, the Assistant City Manager, the Chief Financial Officer, the City Attorney, and the Electric Utility Director. The ROC oversees Roseville's risk management procedures relating to the Electric System and ensures that Electric System's risk profile is within the parameters set forth in the risk management policies.

Roseville's risk management activities for the Electric System are reviewed and monitored routinely by Roseville's risk management committee ("RMC"). The RMC meets quarterly and is comprised of one delegate from the Finance Department, one delegate from the City Attorney's office, the Electric

Utility Director, and three Assistant Electric Utility Directors. The RMC discusses risk mitigation strategies, impacts of various strategies on Roseville's strategic goals for the Electric System and makes recommendations to the ROC, or City Council, as appropriate.

All energy purchases are made in accordance to Roseville's energy risk policies. The Energy Hedge Policy is designed to reduce energy rate volatility and to maintain rates within reasonable tolerances. The Energy Hedge Policy establishes financial and volumetric hedge limits to mitigate market price exposure. Specifically, the policy requires the following fixed price energy contracts to be procured in advance on a rolling three-year horizon, as a percentage of overall energy supply forecast:

Rolling Year	Minimum Hedged Supply	Maximum Hedged Supply
1	90%	110%
2	70%	100%
3	45%	80%

The policy requires that Roseville purchase forward electric contracts and/or forward gas contracts to fulfill its long-term hedged supply requirement. In the event of decreases in expected sales levels, the policy may require that Roseville sell forward electric gas and/or electric contracts. Authorized electric and gas transactions are defined in Roseville's Energy Trading Authority Policy, and executed within its Energy Credit Risk Policy. For the period January 1, 2022 through December 31, 2023, Roseville has fixed the price of approximately [9.75] million MMBtu of natural gas and over [929] GWh of electricity. ***{Please provide update}*** These financial contracts are divided among BP Energy, Conoco Philips, J Aron and Company, Macquarie Energy, EDF Trading North America, and Shell Trading Risk Management.

Fuel Supply; Natural Gas Prepayment

Natural gas is the primary fuel of Roseville's REP and RPP2. See "– Sources of Power Supply." The REP at its optimal output can require delivery of up to 22,000 MMBtu of natural gas per day, with current average daily requirements of approximately 6,500 MMBtu. In early 2007, Roseville undertook a prepaid gas procurement arrangement through the Roseville Natural Gas Financing Authority, pursuant to which such Authority entered into a 20-year pre-paid natural gas supply contract with Merrill Lynch Commodities Inc. ("MLCI") for the supply of natural gas to Roseville. The natural gas Roseville is obligated to purchase under the pre-paid gas supply agreement with the Roseville Natural Gas Financing Authority provides all of Roseville's current gas requirements for the REP. The natural gas supply contract provides Roseville with seasonally adjusted fixed monthly quantities of gas at a discounted monthly index price. To hedge Roseville's natural gas price exposure, Roseville forecasts its expected monthly natural gas requirements and enters into forward natural gas contracts consistent with its risk management policies as noted above.

The fuel supply for Roseville's gas-fired generation facilities is delivered to Roseville through PG&E's natural gas pipeline system.

Regional Transmission Facilities

Western Network Integrated Transmission Service Agreement ("NITS"). Roseville's electric system interconnects with the transmission system of Western. The Western transmission system is part of the Balancing Authority of Northern California ("BANC") balancing authority area and interconnects with the CAISO Controlled Grid. Roseville imports all of its requirements not met by the Roseville Energy Park and the Roseville Power Plant 2 over the Western transmission system. Roseville contracts for transmission service to meet its load under a NITS contract that expires on December 31, 2024. This contract provides for imports of electricity from various delivery points to provide delivery into Roseville's electric system.

Roseville pays a proportionate share of Western's cost for operating and maintaining the system, which is currently $3.2 million per year. Western has indicated that in July 2024 they will begin negotiations on the NITS renewal, with the new contract to be effective on January 1, 2025.

Balancing Authority of Northern California. BANC is a joint powers authority consisting of Roseville, the Sacramento Municipal Utility District ("SMUD"), the Modesto Irrigation District, the City of Redding, the Trinity Public Utility District, and the City of Shasta Lake. A balancing authority performs a balancing function in which customer usage and resources are matched on a moment-by-moment basis. In addition, a balancing authority operates the transmission system, monitoring power lines to ensure they are operated within the reliable limits of the system in addition to coordinating the operation with neighboring balancing authorities. SMUD acts as the balancing authority operator for BANC under contract. With a peak electricity demand of around 5,000 MW, BANC is the third largest balancing authority in California, serving approximately 763,000 retail customers, and includes more than 1,700 miles of high voltage transmission lines. Roseville represents approximately 7% of the total BANC member load.

On April 3, 2019, SMUD, the largest BANC member, began its participation in the CAISO Energy Imbalance Market ("EIM"), a real-time wholesale power trading market that operates in parts of eight western states, including Washington, Oregon, California, Nevada, Idaho, Wyoming, Utah, and Arizona. In addition to modest economic benefits, participation in the EIM is expected to increase BANC members' ability to integrate the renewable energy needed to meet California's environmental goals, provide additional sources of real-time supply to augment reliability resources, allow participants to demonstrate support for regional markets, and retain transaction access to a robust pool of resources. Roseville entered into an agreement with BANC to participate in the EIM and began participating on March 25, 2021.

California Independent System Operator Controlled Grid. The CAISO provides a market for Roseville to purchase its incremental energy needs, and in which to sell the output of its entitlements in NCPA's generating units, and contract purchases. Under current CAISO operating protocols, Roseville pays per MWh charges for uses of the transmission system for exports from CAISO.

TANC California-Oregon Transmission Project ("COTP"). Roseville is a member of the Transmission Agency of Northern California ("TANC") and has executed an agreement (the "TANC Agreement") for a participation percentage of TANC's entitlement of COTP transfer capability. Pursuant to the TANC Agreement, Roseville has a participation share of 2.313% of TANC's entitlement to transfer capability of the COTP (approximately 29.35 MW) and is responsible for 2.313% of TANC's COTP operating and maintenance expenses and 2.295% of TANC's aggregate debt service on a take-or-pay basis. Roseville's share of annual debt service continues to the year 2039 and is approximately $850,000 per year. See also "CITY OF ALAMEDA – Transmission Resources – *TANC California-Oregon Transmission Project*" for a further description of the COTP and the TANC Agreement.

TANC Tesla-Midway Transmission Service. The southern physical terminus of the COTP is near PG&E's Tesla Substation in the San Francisco Bay Area. The COTP is connected to Western's Tracy and Olinda Substations. TANC has arranged for PG&E to provide TANC and its members with 300 MW of firm bi-directional transmission capacity in its transmission system between its Tesla Substation and the Midway Substation (the "Tesla-Midway Service") under an agreement known as the South of Tesla Principles. Roseville's share of the Tesla-Midway Transmission Service is 5 MW. This service has not proven valuable to the City and the City has laid off its rights to this services to other TANC members through 2024.

Roseville Distribution System

Roseville owns and operates the electrical distribution system serving retail customers within the City of Roseville boundaries. The distribution system is connected to the Western transmission system at two connection points, the 230-kV Berry Street Receiving Station and the 230-kV Fiddyment Station. The distribution system consists of over 144 miles of overhead lines, over 786 miles of underground lines, 59 fiber circuit miles, and 18 substations. Roseville performs continued maintenance on its distribution system to sustain service reliability.

Dispatch and Scheduling

Roseville contracts with ACES Power Marketing ("ACES") to provide scheduling services and has discontinued its participation in the NCPA Power Pool. NCPA continues to dispatch the NCPA power plants to meet the schedules of energy delivery prepared and submitted by ACES on Roseville's behalf. NCPA provides dispatch service from its Central Dispatch Center located at its headquarters in Roseville.

Energy Efficiency and Conservation

In 1996, California Assembly Bill 1890 ("AB 1890"), the California electric utility deregulation law, required the establishment of public benefit programs for investor-owned and public power utilities through 2001. In 2006, Assembly Bill 2021 further required power utilities to set yearly goals for the actual amount of energy efficiency savings (in kWh) to be procured. These requirements have been further codified as part of the California Public Utilities Code. The California Public Utilities Code does not set an expiration/sunset date on these requirements for public power utilities. Roseville funds these programs at a minimum of 2.85% of budgeted yearly revenues (approximately $4.5 million in Fiscal Year 2021-22).

Roseville has developed a full portfolio of public benefits programs for the Electric System since 1996, addressing the following areas of concentration required by State law: energy efficiency programs, renewable energy production, demand reduction, advanced electric technology demonstration, research and development, and low income assistance programs. Residential and commercial energy efficiency offerings focus primarily on summer period consumption reduction and include programs for both existing facilities and new construction.

Under California Assembly Bill 2021, Roseville is required to develop ten-year plans for energy efficiency goals and report on these goals to the California Energy Commission ("CEC") with updates every four years. The CEC has the obligation to develop energy efficiency goals for the entire State, after consultation with utilities and others. The Roseville Electric System participates in the State effort, and the Roseville City Council approved the ten-year energy efficiency goals most recently in March 2017. The Roseville Electric System participated in the 2020 Statewide public utility energy efficiency potential study and in March 2021 submitted revised ten-year efficiency goals for approval by the City Council.

California Senate Bill 1037, signed into law in September 2005, established several important policies regarding energy efficiency. Among the many provisions of the law is a Statewide commitment to cost-effective and feasible energy efficiency, with the expectation that all utilities consider energy efficiency before investing in any other resources to meet growing demand. Roseville is required to report annually to its customers and to the CEC, its investment in energy efficiency and demand reduction programs. Roseville continues its commitment to energy efficiency and is in compliance with these requirements.

For a more detailed discussion of certain California legislation in recent years relating to the electric energy market, see "CERTAIN FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY – State Legislation and Regulatory Proceedings" in the front part of this Official Statement.

Employees

General. As of July 1, 2021, 194 City of Roseville authorized positions were assigned specifically to the Electric Department. Meter reading, customer billing and collections were moved to the Electric Department beginning in Fiscal Year 2021-22.

Most of the non-management City personnel working at the Electric System are represented by the International Brotherhood of Electrical Workers ("IBEW"). The current IBEW contract will expire on April 30, 2022. The City of Roseville and IBEW intend to begin negotiations on a new contract in advance of the current contract expiration. There have been no strikes or other work stoppages at the City, including at the Electric System.

Pension Plans. Substantially all permanent Roseville employees, including those employees assigned to the Electric System, are eligible to participate in pension plans offered by the California Public Employees Retirement System ("CalPERS"), an agent multiple employer defined benefit pension plan. CalPERS provides retirement and disability benefits, annual cost-of-living adjustments, and death benefits to plan members, who must be public employees and beneficiaries. CalPERS acts as a common investment and administrative agent for participating public employers within the State. CalPERS issues a separate annual comprehensive financial report. Copies of the CalPERS annual financial report may be obtained from the CalPERS Executive Office, 400 Q Street, Sacramento, California 95814.

CalPERS is a contributory plan deriving funds from employee contributions as well as from employer contributions and earnings from investments. Employees of the Electric System participate in the CalPERS Miscellaneous Plan, and the Electric System pays a percentage of Roseville's Miscellaneous Plan expenses based on the number of employees. Active Miscellaneous Plan members hired prior to January 1, 2013 are required to contribute 8.00% of their annual covered salary and those hired on or after January 1, 2013 are required to contribute 6.25% of their annual covered salary. The member contribution can be paid by the employee or by Roseville on the employee's behalf in accordance with applicable labor agreements. The required member contributions are currently paid by the employees. Roseville's employer contribution rate is determined annually by the actuary 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 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. Roseville is required to contribute the difference between the actuarially determined amount and the contribution rate of employees. The actuarial methods and assumptions used are those adopted by the CalPERS Board of Administration. The contribution requirements of the plan members are established by State statute and the employer contribution rates are established, and may be amended, by CalPERS.

The table below sets forth Electric System's allocated share of Roseville's required contributions to the Miscellaneous Plan for the past five Fiscal Years. The Electric System's estimated allocated share of Roseville's budgeted contributions to the Miscellaneous Plan for the Fiscal Year ending June 30, 2022 is $7,868,584.

	City of Roseville Miscellaneous Plan		
Fiscal Year	**Electric System Allocated Share of Contributions**	**Total City Contribution Amount**	**Contributions as a % of Covered Payroll**
2016-17	$4,699,119	$19,896,723	26.54%
2017-18	4,463,913	18,499,075	23.96
2018-19	5,112,952	20,601,494	23.88
2019-20	5,888,148	23,130,931	28.76
2020-21	7,058,610	27,226,777	31.48

Source: City of Roseville.

Roseville'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 Roseville's required contributions to CalPERS in future years.

On December 21, 2016, the CalPERS Board of Administration lowered the discount rate from 7.5% to 7.0% using a three year phase-in beginning with the June 30, 2016 actual valuations, and beginning with Fiscal Year 2017-18 CalPERS changed the employer contributions toward the plan's unfunded liability as dollar amounts instead of prior method of a contribution rate. The announcement on July 12, 2021 that CalPERS achieved a preliminary investment return of 21.3% for the period from July 1, 2020 through June 30, 2021 caused the CalPERS Board of Administration to lower CalPERS' discount rate from 7.0% to 6.8% on November 15, 2021 in accordance with a risk mitigation policy that was adopted in 2015, which calls for the discount rate to be lowered if returns exceed the then-current discount rate by two or more percentage points. Lowering the discount rate generally means that employers which contract with CalPERS to administer their pension plans will see increases in their normal costs and unfunded actuarial liabilities. The CalPERS Board of Administration may in the future further adjust certain assumptions used in the CalPERS actuarial valuations, which adjustments may increase Roseville's required contributions to CalPERS in future years. Accordingly, Roseville cannot provide any assurances that Roseville's required contributions to CalPERS in future years will not significantly increase (or otherwise vary) from any past or current projected levels of contributions.

Effective for the Fiscal Year ended June 30, 2015, Roseville adopted Governmental Accounting Standards Board ("GASB") Statement No. 68 ("GASB No. 68"), affecting the reporting of pension liabilities for accounting purposes. Under GASB No. 68, Roseville 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 Net Pension Liability of the Miscellaneous Plan as of June 30, 2016 through June 30, 2020 (as reported in Roseville's audited financial statements as of the succeeding fiscal year). The Electric System's allocable share of Roseville's net pension liability was not separately determined.

	City of Roseville Miscellaneous Plan				
Measurement Date[1] (June 30)	Total Pension Liability	Plan Fiduciary Net Position	Net Pension Liability	Net Position as a % of Total Pension Liability	Net Pension Liability as a % of Covered Payroll
2016	$565,400,677	$361,251,067	$204,149,610	63.89%	275.38%
2017	632,299,916	403,695,744	228,604,172	63.85	305.94
2018	667,324,796	435,184,425	232,140,371	65.21	291.57
2019	708,947,152	461,423,549	247,523,603	65.09	311.23
2020	746,608,126	481,927,863	264,680,263	64.55	329.13

(1) Measured using prior fiscal year annual actuarial valuation rolled forward to measurement date using standard update procedures.

Source: City of Roseville.

In the June 30, 2020 actuarial valuation utilized for measuring the pension liability as of the June 30, 2019 measurement date, the Entry Age Normal Actuarial Cost Method was used. The actuarial valuation assumptions used for determining total pension liabilities included (a) a 7.15% investment rate of return (net of pension plan investment and administrative expense); (b) projected salary increases that range from 3.3% to 14.2% annually; (c) an inflation component of 2.50% per year; (d) payroll growth of 3.0%; and (e) a discount rate of 7.15%.

Retiree Health Benefits. Roseville also provides post-employment medical benefits ("OPEB benefits") to substantially all retirees, including those assigned to the Electric System, under the City of Roseville Retiree Healthcare Plan, a sole employer defined healthcare plan administered by the Trust Investment Review Committee. Roseville is responsible for establishing and amending the funding policy of the plan. Roseville manages the plan by investing assets in a Retiree Health Plan Trust (the "OPEB Trust"), established pursuant to a Trust Agreement, and managed by the OPEB's Trust Administrator, PFM Asset Management LLC. As of June 30, 2021, there were 1,343 participants receiving OPEB benefits under the plan.

The contribution requirements of plan members and Roseville are established and may be amended by the Roseville City Council. The City Council establishes rates based on an actuarially determined rate.

Effective beginning in Fiscal Year 2017-18, Roseville 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 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 affect funding requirements.

The table below sets forth certain information regarding the Electric System's allocated share of Roseville's annual contributions to the OPEB Plan for the four Fiscal Years 2017-18 through 2020-21, including the relation of Roseville's contributions to the actuarially determined contribution amount for such fiscal year. The Electric System's estimated allocated share of Roseville's budgeted contributions to the OPEB Plan for the Fiscal Year ending June 30, 2022 is $2,300,000.

	City of Roseville OPEB Plan			
Fiscal Year Ended June 30	Contribution Funded by Electric System	Total City Contribution	Actuarially Determined Contribution Amount	Contribution Deficiency (Excess) to Actuarially Determined Contribution
2018[(1)]	$ 2,016,000	$ 14,213,000	$ 15,132,000	$ 919,000
2019	2,079,000	15,226,000	15,342,000	116,000
2020	2,224,000	13,739,000	16,485,000	(2,746,000)
2021	2,286,000	14,026,000	15,353,152	(1,327,152)

(1) First fiscal year of implementation of GASB No. 75.

Source: City of Roseville.

The City's net OPEB liability was measured as of June 30, 2021, and the total OPEB liability used to calculate the net OPEB liability was determined by an actuarial valuation as of June 30, 2019. The total OPEB liability was $242,704,968 and the OPEB Plan fiduciary net position was $143,077,125, resulting in a net OPEB liability of $99,627,843 as of June 30, 2021. Plan fiduciary net position as a percentage of the total OPEB liability was 58.95%. The net OPEB liability as a percentage of covered payroll was 86.22%. In the June 30, 2019 actuarial valuation utilized in determining the OPEB liability, the Entry Age Normal Actuarial Cost Method was used with a 24-year fixed amortization period and level percentage of pay. The actuarial valuation assumptions used include (a) a 6.00% investment rate of return (net of administrative expense); (b) projected salary increases of 3% annually; (c) an inflation component of 2.75% per year; and (d) a healthcare trend 7.5% for 2020, decreasing to an ultimate rate of 4% in 2076 for non-medicare participants, and 6.5% in 2020, decreasing to an ultimate rate of 4.0% in 2076 for medicare participants.

Additional information regarding the City of Roseville's retirement plans and other post-employment benefits can be found in Roseville's annual comprehensive financial reports, which may be obtained at *www.roseville.ca.us.*

Insurance

Roseville is a member of the California Joint Powers Risk Management Authority ("CJPRMA"), which covers general liability claims, property, and boiler and machinery losses. Once Roseville's deductible is met, CJPRMA becomes responsible for payment of all claims up to the limit. General liability claims are covered up to $40,000,000 with a self-insured retention of $500,000 per claim. For Fiscal Year 2020-21, Roseville's premium was $1,008,371. CJPRMA has purchased commercial insurance against property damage and boiler and machinery claims. Property damage is covered up to $400,000,000 with a self-insured retention of $500,000 per claim. Boiler and Machinery damage is covered up to $21,250,000 with a self-insured retention of $5,000. For Fiscal Year 2020-21, the annual premium cost for both was $528,646.

Additionally, Roseville maintains insurance coverage for liabilities arising from the Roseville Energy Park property. The policy has a self-insured retention of $250,000 per claim up to a $200,000,000 limit. For the policy term of October 13, 2020 through October 13, 2021, Roseville's premium is $658,399. Roseville has also purchased fiduciary insurance specifically to cover the OPEB Trust; see "Employees – *Other Post-Employment Health Benefits*" above. The self-insured retention was $25,000 per claim up to a $3,000,000 limit. For the policy term of January 15, 2020 through January 15, 2021, Roseville's premium was $35,419.

Roseville is a member of the Local Agency Workers' Compensation Excess Joint Powers Authority ("LAWCX"), which covers workers' compensation claims up to $5,000,000 and provides additional coverage up to statutory limit. Roseville has a self-insured retention of up to $500,000 per claim. For Fiscal Year 2020-21, Roseville's premium cost was $1,220,000.

Wildfire Mitigation Measures

Roseville does not independently own any transmission lines, and its owned or co-owned transmission or distribution facilities have not been the cause of any recent wildfires experienced in California. The municipal boundaries of the City of Roseville, the primary geographical area in which the Roseville Electric System's overhead electrical lines and equipment are located, is not currently within a California Public Utilities Commission ("CPUC") designated fire-threat area nor a United States Forest Service/California Department of Forestry and Fire Protection (Cal Fire) designated high hazard zone. In 2018, Roseville staff determined, in consultation with the City of Roseville Fire Department, and based upon historical data, local experience and reference to the CPUC's High Fire Threat District Maps, that there were no portions of the geographical area in which the utility's overhead electrical lines and equipment are located that posed a significant risk of wildfire resulting from those electrical lines and equipment. As a precautionary measure, Roseville has developed and implemented a utility preparedness plan to address wildland fire sensitive areas and other possible utility emergency events. Elements of the 2018 utility preparedness plan include bolstered inspection practices for overhead electrical assets within the designated city wildland fire sensitive areas, ongoing vegetation management activities, and established protocols and procedures for operations for emergency preparedness and response. Roseville prepared a wildfire mitigation plan in accordance with the requirements of SB 901. On December 4, 2019, the report of the independent evaluator was presented and accepted by the Roseville City Council as required by SB 901. The Roseville City Council most recently approved its 2022 wildfire mitigation plan and accepted the report of the independent evaluator on December 15, 2021. See also "CERTAIN FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY – State Legislation and Regulatory Proceedings – Legislation Relating to Wildfires; Related Risks" in the front part of this Official Statement.

COVID-19

The spread of the novel strain of coronavirus (and variants thereof) and the disease it causes (now known as "COVID-19") has had significant negative impacts throughout the world, including in California. In 2020, the World Health Organization declared the COVID-19 outbreak to be a pandemic, and states of emergency have been declared by the United States, the State and numerous counties throughout the State. The purpose behind these declarations was to coordinate and formalize emergency actions across federal, state and local governmental agencies, and to proactively prepare for a wider spread of the virus.

On March 19, 2020, in an effort to slow the spread of COVID-19, Governor Newsom issued Executive Order N-33-20 ordering individuals living in the State to stay home or at their place of residence except for specified exceptions, including exceptions for certain sectors of the workforce that were classified as providing essential services and products, which allowed businesses and workers in such sectors to continue to operate on-site operations while Executive Order N-33-20 was effective. On June 11, 2021, Governor Newsom issued two executive orders, which became effective on June 15, 2021, which had the effect of rescinding a majority of the COVID-19-related restrictions and providing a timeline for gradually lifting certain of the other restrictions that were not fully rescinded on June 15, 2021.

During the pandemic, Roseville initially experienced a decline in electricity demand by small to medium sized commercial customers, while electricity usage by residential customers increased, as might be expected with many retail establishments being closed and people staying home. The pandemic customer load and revenue impacts to Roseville were largely limited to Fiscal Year 2019-20. Roseville experienced an overall increase in load in Fiscal Year 2020-21, driven by stronger than expected residential customer use and warmer temperatures. For information regarding Roseville's load requirements over the past five Fiscal Years, see "– Power Supply Resources." For information regarding the types of businesses comprising the Electric System's largest customers, see "– Major Customers." See also "Customers, Energy Sales, Revenues and Demand."

Historically, the annual write-offs for uncollectible accounts have been less than 0.20% of gross billings of the Electric System.. To help mitigate the economic impact of COVID-19 and the related governmental regulations on its customers, Roseville implemented a payment deferral program for all customers of Roseville utilities, which included the suspension of the disconnection of services by City utilities for non-payment of utility bills for a period beginning in March 2020 and extending through June 2021.

Roseville was allocated approximately $0.5 million under the California Department of Community Services and Development California Arrearage Payment Program ("CAPP"), to aid the accounts that have fallen behind during the period of May 4, 2020 through June 15, 2021, which in turn is expected by Roseville to lower its uncollectible revenue amount. Roseville received the funding in January 2022. Collectively, the resumption of utility service disconnections and applying the CAPP funds reduced the past due bills exceeding sixty-one days to less than $0.6 million, returning to near pre-pandemic levels.

With widespread vaccination currently underway in the United States and many countries worldwide, governmental-imposed stay-at-home orders and restrictions on operations of schools and businesses implemented to respond to and control the outbreak have been eased or eliminated. However, restrictions may be re-imposed in various jurisdictions from time to time as local conditions warrant. Roseville cannot predict whether any reinstatement or expansion of stay-at-home orders and travel or other restrictions will occur or when a full resumption of all economic activity will be achieved. The ultimate impact of COVID-19 on the operations and finances of Roseville or the Electric System is unknown and there can be no assurances that COVID-19 will not materially adversely impact the financial condition of Roseville or the Electric System in the future. There are many variables that will continue to contribute to the economic impact of the COVID-19 pandemic and the recovery therefrom, including the length of time social distancing measures are in place, the effectiveness of State and federal government relief programs and the timing for containment and treatment, new coronavirus strains, vaccinations efforts and vaccine hesitancy. Roseville cannot predict the extent or duration of such impacts.

Projected Capital Improvements

Roseville's currently anticipated capital improvements for the Electric System encompasses both improvements to Roseville's electricity distribution system and rehabilitation projects for assets that can no longer provide the necessary service. As shown in the Capital Improvement Summary below, Roseville has planned Electric System capital spending of approximately $101.5 million over the five Fiscal Years 2021-22 through 2025-26, of which $22.3 million is included in the approved Fiscal Year 2021-22 budget. Funds for the additional $79.2 million will be requested when necessary.

CITY OF ROSEVILLE
ELECTRIC SYSTEM
CAPITAL IMPROVEMENT SUMMARY

Fiscal Year Ending June 30	Capital Improvement Projects
2021-22	$22,313,520
2022-23	24,012,932
2023-24	20,938,000
2024-25	16,109,000
2025-26	18,146,000
Total:	$101,519,452

Source: City of Roseville.

Roseville currently expects to fund the capital expenditures primarily with revenues collected from rates and developer fees. Developer fees are estimated to fund $33.1 million of the $101.5 million of the planned capital improvement projects over Fiscal Years 2021-22 through 2025-26.

Electric Rates

Rate Setting Procedure. Under the City Charter and State law, Roseville has the exclusive jurisdiction to set electric rates within its service area by ordinance, which requires a majority vote of the City Council. These rates are not currently subject to review by the CPUC or any State or federal agency. The City Council reviews Electric System rates periodically and makes adjustments as necessary.

The City Council is also authorized by the City Charter to set charges, pay for and supply all electric power to be furnished to customers according to such schedules, tariffs, rules and regulations as are adopted by the City Council. The City Charter provides that the City Council will have the power to charge equitable rates for the electric services furnished and for building up the electric properties so as to conserve their value and increase their capacity as needed by Roseville. In addition, the City Charter provides for the maintenance of the electric funds for the Electric System into which is deposited receipts from the operations of the Electric System and from which the costs and expenses of the Electric System are payable.

Service Charges and Demand Charge. Roseville's monthly residential electric rates currently include a $28.00 basic service charge, the Renewable Energy Surcharge of $0.0056 per kWh, the Greenhouse Gas Surcharge of $0.0002 per kWh, plus $0.0959 per kWh consumed up to 500 kWh, and $0.1442 per kWh for consumption in excess of 500 kWh. Residential customers meeting certain criteria can apply for special residential rates such as an Electric Rate Assistance Program and Medical Support Rate Reduction.

For small and medium business customers, the monthly basic service charge ranges from $41.00 to $65.00, the Renewable Energy Surcharge of $0.0056 per kWh, the Greenhouse Gas Surcharge of $0.0002 per kWh, plus $0.0995 to $0.1258 per kWh consumed. Medium business customers are also subject to a demand charge of $6.16 per kW per month.

For large business customers, the monthly basic service charge is $541.00, the Renewable Energy Surcharge of $0.0056 per kWh, the Greenhouse Gas Surcharge of $0.0002 per kWh; and depending on the season, day and hour, time of use energy charges vary from $0.0699 to $0.1444 per kWh. Large business customers are also subject to a seasonal demand charge of $6.60 per kW per month in winter and $11.57 per kW per month in summer.

For very large business customers, the monthly basic service charge is $616.00, the Renewable Energy Surcharge of $0.0056 per kWh, the Greenhouse Gas Surcharge of $0.0002 per kWh; and depending on the season, day and hour, time of use energy charges vary from $0.0691 to $0.1432 per kWh. Very large business customers are also subject to a seasonal demand charge of $6.71 per kW per month in winter and $11.51 per kW per month in summer.

A hydroelectric adjustment formula was adopted by the City Council in March 2009, to reflect deviations of precipitation from average conditions that significantly change hydroelectric production. This surcharge may change annually, based on annual hydroelectric conditions, up to a maximum of 5% of total electric charges. As a result of lower than average precipitation, a surcharge of 3.60% is effective from September 2021 through June 2022.

Recent History of Electric Rate Adjustments. From Fiscal Year 2017-18 through 2021-22, Roseville's retail electric rates have increased an average of approximately 0.40% annually. The following table sets forth Roseville's recent rate change history and the effective date.

CITY OF ROSEVILLE
RATE ADJUSTMENTS
Fiscal Years 2017-18 through 2021-22

Date	Percent Change (Average)
January 1, 2022	2.00% [(1)]
January 1, 2021	0.00
January 1, 2020	0.00
January 1, 2019	0.00
January 1, 2018	0.00

(1) Medium commercial customer rates increased 1.50%. All other customer groups increased 2.00%.
Source: City of Roseville.

Rate Stabilization Fund

On May 8, 1996, the City Council adopted Resolution No. 96-148, which provides for, among other policies, the establishment of a rate stabilization fund (the "RSF" or "Rate Stabilization Fund"), in order to remain competitive under the then occurring industry-wide restructuring of the electric industry. Such policies also provide for the recovery of capital costs of Roseville's electric generating assets. On March 18, 2009, the City Council reviewed the financial policy that defines the range of the Rate Stabilization Fund balance, reducing the minimum balance from 60% to 40% and a maximum 90% of operating expenses. This action was taken in conjunction with the implementation of a hydroelectric rate adjustment mechanism that adjusts electric rates up to 5% without further City Council action when hydroelectric conditions increase or decrease electric operating expenses. See also "– Electric Rates." The Rate Stabilization Fund has a balance of $68 million as of June 30, 2021. Roseville estimates that under current revenue estimates, the Rate Stabilization Fund is expected to be sufficient to pay for currently anticipated contingencies related to power supply costs.

Indebtedness; Joint Powers Agency Obligations

Roseville Electric System Revenue Certificates and Bonds. As of January 31, 2022, Roseville had outstanding approximately $153,480,000 principal amount of certificates of participation and refunding revenue bonds (the "Outstanding Electric System Certificates and Bonds") that were executed and delivered to finance and refinance improvements to the Electric System. The Outstanding Electric System Certificates and Bonds are payable from certain payments to be made by Roseville under an installment purchase contract (the "Installment Purchase Contract"), the payments under which are payable from and secured by the Net Revenues of the Electric System ("Net Revenues" are defined generally as revenues of the Electric System less the maintenance and operation costs of the Electric System during any 12-month period). These obligations are subordinate to the payments required to be made with respect to Roseville's obligations to NCPA and TANC described below.

Roseville's Outstanding Electric System Certificates and Bonds are summarized in the table below.

CITY OF ROSEVILLE
OUTSTANDING ELECTRIC SYSTEM INDEBTEDNESS
(as of January 31, 2022)

Name of Issue	Principal Amount Outstanding
Roseville Electric Utility System Revenue Certificates	
Series 2004 Certificates	$ 5,000
Series 2012 Refunding Certificates	54,000,000
Roseville Finance Authority	
Electric Utility System Bonds	
Refunding Revenue Bonds, Series 2013	6,290,000
Refunding Revenue Bonds, Series 2017A	56,210,000
Refunding Revenue Bonds, Taxable Series 2017B	2,525,000
Revenue Refunding Bonds, Taxable Series 2020	34,450,000
Total	$153,480,000

Source: City of Roseville.

Roseville's Series 2012 Refunding Certificates reflected in the table above are variable rate obligations which were purchased by U.S. Bank National Association (the "Bank") in a direct purchase transaction. Such variable rate obligations bear interest at a per annum rate determined monthly based upon a spread to a percentage of the one-month London InterBank Offering Rate ("LIBOR") and are subject to mandatory tender for purchase on the scheduled mandatory tender date of May 1, 2023, or, if directed by the Bank upon the occurrence and continuance of an event of default under the related continuing covenant agreement, seven calendar days after receipt of such direction. On or before the scheduled mandatory purchase date, Roseville may request may request the Bank to purchase such variable rate obligations in another index rate period or another interest rate mode, or Roseville may seek to remarket such variable rate obligations to another bank or in the public debt markets. Prior to the issuance of such variable rate obligations, Roseville entered into certain interest rate swap agreements. The notional amount of the remaining outstanding interest rate swap was $54,000,000 as of June 30, 2021. Pursuant to the terms of the currently outstanding interest rate swap agreement, the floating rate interest payments that Roseville is obligated to make with respect to the variable rate Series 2012 Refunding Certificates were converted into substantially fixed rate payments. In general, the terms of the interest rate swap agreement provides that on a same-day net payment basis, Roseville will pay a fixed interest rate determined based upon the notional amount of the interest rate swap and in return the swap counterparty will pay a variable rate of interest on a like notional amount. The City's obligation to make any net regularly scheduled payments due to the swap counterparty under the interest rate swap agreement is payable on parity with the Outstanding Electric System Certificates and Bonds and is subordinate to the payments required to be made with respect to Roseville's joint powers agency obligations described under "– *Joint Powers Agency Obligations*" below (including under the Third Phase Agreement). Under certain circumstances, the interest rate swap agreement is subject to termination and Roseville may be required to make a substantial termination payment to the counterparty thereunder. Any termination payments due from Roseville under the interest rate swap agreement upon early termination thereof are payable on a basis that is junior and subordinate to the payment of Roseville's Outstanding Electric System Certificates and Bonds.

Joint Powers Agency Obligations. As previously discussed, Roseville participates in certain joint powers agencies, including NCPA and TANC. The obligations of Roseville under its agreements with NCPA and TANC constitute operating expenses of the Electric System payable on a senior basis to any of the payments required to be made on Roseville's Outstanding Electric System Certificates and Bonds. The agreements with NCPA and TANC are on a "take-or-pay" basis, which requires payments to be made whether or not projects are operable, or whether output from such projects is suspended, interrupted or terminated. These agreements contain "step up" provisions obligating Roseville to pay a share of the obligations of a defaulting participant and granting Roseville a corresponding increased entitlement to electricity (generally, Roseville's "step-up" obligation is limited to 25% of Roseville's scheduled payments on such obligations). Roseville'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.

CITY OF ROSEVILLE
ELECTRIC SYSTEM
OUTSTANDING DEBT OF JOINT POWERS AGENCIES[(1)]
(Dollar Amounts in Millions)
(As of January 31, 2022)

	Outstanding Debt[(2)]	Roseville Participation[(3)]	Roseville Share of Outstanding Debt[(2)]
NCPA			
Geothermal Project	$ 10.8	7.88%	$ 0.9
Hydroelectric Project	223.3	12.00[(4)]	22.1
Capital Facilities Project	13.8	36.50	5.0
TANC			
COTP	169.9	2.32	3.9
TOTAL[*]	$417.8		$31.9

(1) Excludes Roseville Natural Gas Financing Authority. See "Natural Gas Prepayment" above.
(2) Principal only. Does not include obligation for payment of interest on such debt.
(3) Participation based on actual debt service obligation. Participation obligation is subject to increase upon default of another project participant. Such increase shall not exceed, without written consent of a non-defaulting participant, an accumulated maximum of 25% of such non-defaulting participant's original participation.
(4) Roseville's actual payments represent approximately 9.9% of outstanding debt service as a result of credit received by it as a non-participating member with respect to portion of debt obligation.

Note: Numbers may not total due to rounding.

Source: City of Roseville.

A portion of the joint powers agency debt obligations are variable rate bonds, liquidity support for which is provided through liquidity arrangements with banks. Unreimbursed draws under liquidity arrangements supporting joint powers agency variable rate debt obligations bear interest at a maximum rate substantially in excess of the current interest rates on such obligations. Moreover, in certain circumstances, the failure to reimburse draws on the liquidity agreements may result in the acceleration of scheduled payment of the principal of such variable rate joint powers agency obligations. To the extent a joint powers agency has entered into interest rate swap agreements for the purposes of substantially fixing the interest cost with respect to variable rate joint powers agency obligations, there is no guarantee that the floating rate payable to such joint powers agency pursuant to such interest rate swap agreements will match the variable interest rate on the associated variable rate joint powers agency debt obligations to which the respective interest rate swap agreement relates at all times or at any time. Under certain circumstances, the swap providers may be obligated to make payments to the applicable joint powers agency under their respective interest rate swap agreement that is less than the interest due on the associated variable rate joint powers agency debt obligations to which such interest rate swap agreement relates. In such event, such insufficiency will be payable as a debt service obligation from the obligated joint powers agency members (a corresponding amount of which proportionate to its debt service obligations to such joint powers agency could be due from Roseville). In addition, under certain circumstances, each of the swap agreements is subject to early termination, in which event the joint powers agency could be obligated to make a substantial payment to the applicable swap provider (a corresponding amount of which proportionate to its debt service obligations to such joint powers agency could be due from Roseville). The only currently outstanding interest rate swap agreement related to Roseville's variable rate joint powers agency debt obligations is the 2008 Series A Hydroelectric Swap which is expected to be terminated in connection with the issuance of the 2022 Bonds. See "PLAN OF REFUNDING" in the front part of this Official Statement.

Litigation

There is no action, suit or proceeding known to be pending or threatened, restraining or enjoining Roseville in the execution or delivery or performance of, or in any way contesting or affecting the validity of any proceedings of Roseville taken with respect to, the Third Phase Agreement.

There is no litigation pending, or to the knowledge of Roseville, threatened, questioning the existence of Roseville, or the title of the officers of Roseville to their respective offices. There is no litigation pending, or to the knowledge of Roseville, threatened, questioning or affecting in any material respect the financial condition of Roseville's Electric System.

Present lawsuits and other claims against Roseville's Electric System are incidental to the ordinary course of operations of the Electric System and are largely covered by Roseville's self-insurance program. In the opinion of Roseville's management and the Roseville City Attorney, such claims and litigation will not have a materially adverse effect upon the financial position of Roseville.

Financial Information

Significant Accounting Policies. Governmental accounting systems are organized and operated on a fund basis. A fund is defined as an independent fiscal and accounting entity with a self-balancing set of accounts recording cash and other financial resources, together with all related liabilities and residual equities or balances, and changes therein. Funds are segregated for the purpose of carrying on specific activities or attaining certain objectives in accordance with special regulations, restrictions or limitations.

The Electric System is accounted for as an enterprise fund. Enterprise funds are used to account for operations (i) that are financed and operated in a manner similar to private business enterprises (where the intent of the governing body is that the costs (expenses, including depreciation) of providing goods or services to the general public on a continuing basis be financed or recovered primarily through user charges) or (ii) where the governing body has decided that periodic determination of revenues earned, expenses incurred and/or net income is appropriate for capital maintenance, public policy, management control, accountability or other purposes.

The Electric Fund uses the accrual method of accounting. Revenues are recognized when they are earned and expenses are recognized when they are incurred.

Investments are stated at cost. Inventories are valued at weighted average method. Capital assets are recorded at historical cost. Donated fixed assets are valued at their estimated fair market value on the date donated.

Audited Financial Statements. Roseville's most recent Annual Comprehensive Financial Report for Fiscal Year 2020-21 was audited by Lance, Soll & Lunghard, LLP, Sacramento, California, in accordance with generally accepted auditing standards. The audited financial statements contain opinions that the financial statements present fairly the financial position of the various funds maintained by Roseville. The reports include certain notes to the financial statements which are not fully described below. Such notes constitute an integral part of the audited financial statements. Copies of these reports are available on Roseville's website, *www.roseville.ca.us*.

Historical Revenues, Expenses and Debt Service Coverage

The following table presents a summary of the revenues, expenses, and debt service coverage for Roseville's Electric Fund for Fiscal Years 2016-17 through 2020-21 on a historical basis. The information is derived from Roseville's audited financial statements for Fiscal Years 2016-17 through 2020-21. This table is based on historic operating results of the Electric System, but is presented on a cash basis consistent with the definitions of revenues and maintenance and operation costs as defined in the Installment Purchase Contract relating to Roseville's Outstanding Electric System Certificates and Bonds, and as such, does not match the audited financial statements of the Electric System. The table also includes a five-year history of balances in the Rate Stabilization Fund, and calculates debt service coverage both with and without taking into account the Rate Stabilization Fund balance.

The table below as it is presented is not available in Roseville's audited financial statements for the Electric System; it has been designed to reflect revenues and coverage in a manner which meets GAAP standards and is reflective of the definitions of revenues and maintenance and operation costs as defined in the Installment Purchase Contract relating to Roseville's Outstanding Electric System Certificates and Bonds. The figures shown in the table for Fiscal Years 2016-17 through 2020-21 are accounted for in Roseville's audited financial statements for such years but the presentation in the audited financial statements may not necessarily correlate to the line item designations in the table.

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CITY OF ROSEVILLE
ELECTRIC FUND
STATEMENT OF REVENUES AND EXPENSES
Fiscal Years 2016-17 through 2020-21
(Dollars in Thousands)

	2016-17	2017-18	2018-19	2019-20	2020-21
Revenues					
Charges for Services	$161,515	$162,501	$158,667	$157,695	$165,995
Other	4,169	5,735	9,380[6]	4,852	1,782
Total Revenues	$165,684	$168,236	$168,047	$162,548	$167,777
Operating Expenses					
Power Supply [1]	$ 81,204	$ 77,090	$ 68,810[8]	$ 69,107	$ 68,497
Non-Power Costs [2]	36,771	37,470	37,085	45,878	54,842
Indirect Costs and Transfers [3]	8,297	3,146	3,582	1,967	2,975
Total Operating Expenses	$126,272	$117,706	$109,477	$116,952	$126,314
Net Revenue	$ 39,412	$ 50,530	$ 58,570	$ 45,596	$ 41,643
Debt Service	$ 15,950	$ 16,672	$ 15,773	$ 14,943	$ 14,096
Adjusted Net Revenue					
Net Revenue	$ 39,412	$ 50,530	$ 55,570	$ 45,596	$ 41,643
Interest Revenue (excluding unrealized gain/loss)	$ 1,887	$ 2,497	$ 4,986	$ 3,871	$ 2,538
Adjusted Net Revenue	$ 41,299	$ 53,027	$ 63,556	$49,467	$ 44,181
Debt Service Coverage Ratio	2.61	3.11	4.03	3.31	3.13
Rate Stabilization Fund Balance [4]	$ 58,943	$ 58,811	$ 65,671	$68,024	$67,988
Transfers from/(to) Rate Stabilization Fund	0	0	(5,000)	0	0
Debt Service Coverage ratio, including Rate Stabilization Fund [5]	6.28	6.71	8.19	7.86	7.96

(1) Includes joint powers agency payment obligations.
(2) Includes distribution operations and administration expenses, including the Electric System's share of CalPERS costs.
(3) In Fiscal Year 2016-17, includes operating payments to the City General Fund as reimbursement for the Electric System's share of certain overhead expenses such as information technology, meter reading, traffic signals, payroll, human resources, facility lease payments, utility exploration center operations, retired employees' health costs, OPEB costs, citywide rehabilitation costs, etc. As of Fiscal Year 2017-18, most of such costs were moved to Non-Power costs with retired employees' health costs, OPEB costs, and citywide rehabilitation costs remaining on this line. The increase to Non-Power costs was offset by other operational savings.
(4) Represents available resources as of June 30.
(5) Pursuant to the Installment Purchase Contract relating to Roseville's Outstanding Electric System Certificates and Bonds, funds on deposit in the Rate Stabilization Fund may be included in Adjusted Annual Revenues for purposes of determining compliance with the Rate Covenant. See "Rate Setting – Rate Stabilization Fund."
(6) Increase in "Other" Revenues in Fiscal Year 2018-19 is attributable to approximately $1.5 million in mutual aid reimbursement, $1.0 million in low carbon fuel ("LCFS") credits, and $0.5 in proceeds from cap-and-trade auction proceeds.
(7) Decrease in "Power Supply" Operating Expenses for Fiscal Year 2018-19 is attributable to a change in accounting for wholesale revenues and expenses such that beginning in Fiscal Year 2018-19 net wholesale revenues and expenses are no longer accounted for in Power Supply expenses; wholesale revenues are reflected in Other Revenues.

Source: City of Roseville.

CITY OF SANTA CLARA

Introduction

The City of Santa Clara ("Santa Clara") is a charter city located in the State of California (the "State"). Pursuant to its charter, Santa Clara has the power to furnish electric utility service within its service area. In connection therewith, Santa Clara has the powers of eminent domain, to contract, to construct works, to fix rates and charges for commodities or services it provides and to incur indebtedness.

Santa Clara provides electric utility service through its electric utility department. Santa Clara offers its electricity and energy services through the trademarked name of "Silicon Valley Power." In addition, Santa Clara provides other city services to its inhabitants, including police and fire protection, and water and sewer service.

The legal responsibilities and powers of Santa Clara, including the establishment of rates and charges for electric service, are exercised by the seven-member Santa Clara City Council. The Santa Clara City Council is made up of the Mayor, elected at large, and six council members. The members of the Santa Clara City Council have historically been elected city-wide for staggered four year terms under the provisions of the City Charter. However on July 23, 2018, the Santa Clara County Superior Court issued a statement of decision in the case, *LaDonna Yumori Kaku et al. v. City of Santa Clara*, ordering the City to implement by-district elections for its six council members. Following the court decision, the two Council seats that were up for election in the November 6, 2018 election were elected by district election. Santa Clara lost the appealed of the trial court decision in December 2020 and is implementing the six district election process.

The Santa Clara electric utility department is under the direction of the Chief Electric Utility Officer who, together with certain other senior managers of the electric utility department, is appointed by and reports to the Santa Clara City Manager.

To provide electric service within its service area, Santa Clara owns and operates an electric system which includes generation, transmission and distribution facilities. Santa Clara also purchases power and transmission services from other providers and participates in other utility type arrangements.

Since 1896, Santa Clara has provided all electric service within an area coterminous with the City of Santa Clara's boundaries. As of January 1, 2021, Santa Clara had an estimated population of 130,746. For the Fiscal Year ended June 30, 2021, Santa Clara served an average of 59,191 customer accounts per month, had total sales of approximately 3,853 GWh and a peak demand of 593.1 MW. In the Fiscal Year ended June 30, 2021, approximately 92.5% of Santa Clara's energy sales were made to commercial and industrial customers.

Only revenues of the Santa Clara electric utility department will be available to pay amounts owed by Santa Clara under the Third Phase Agreement.

The Santa Clara electric utility department's main office is located at Santa Clara City Hall, 1500 Warburton Avenue, Santa Clara, California 95050, (408) 615-6600. A copy of the most recent audited financial statements of the Santa Clara Electric Utility Enterprise Fund (the "Annual Report") may be obtained from Manuel Pineda, Chief Electric Utility Officer, at the above address and telephone number, and is also available on Santa Clara's website at *www.siliconvalleypower.com* and on the Municipal Securities Rulemaking Board's Electronic Municipal Market Access system at *http://emma.msrb.org/*. The Annual Report is incorporated herein by this reference. However, the information presented on such website or referenced therein other than the Annual Report is not part of this Official Statement, is not incorporated by reference herein and should not be relied upon in making an investment decision with respect to the 2022 Bonds.

Power Supply Resources

The following table sets forth information concerning Santa Clara's power supply resources and the energy supplied by each during the Fiscal Year ended June 30, 2021.

CITY OF SANTA CLARA
ELECTRIC UTILITY DEPARTMENT
POWER SUPPLY RESOURCES
(For the Fiscal Year Ended June 30, 2021)

Source	Capacity Available (MW)	Recorded Energy (GWh)	Percent of Total Energy
City-Owned Generating Facilities[1]			
Cogeneration	7.0	50.0	1.3%
Stony Creek Hydro System	11.6	5.3	0.1
Gianera Generating Station	49.5	9.0	0.2
Grizzly Project	17.7	0.0	0.0
Donald Von Raesfeld Power Plant	147.8	789.6	20.0
Jenny Strand Solar Park	0.1	0.2	0.0
Purchased Power:[2]			
Western Area Power Administration[3]	136.0	202.6	5.1
Manzana Wind	50.0	143.4	3.6
G2 (Landfill)	1.5	13.0	0.3
Ameresco (Landfill)	0.8	2.2	0.1
Ameresco FWD (Landfill)	4.2	32.5	0.8
Ameresco VASCO (Landfill)	4.3	34.3	0.9
TriDam-Beardsley	11.5	28.0	0.7
TriDam-Donnells	72.0	137.8	3.5
TriDam-Tulloch	25.9	103.6	2.6
TriDam-Sandbar	16.2	32.3	0.8
Rio Bravo	14.0	11.3	0.3
Rosamond (Recurrent Solar)	20.0	59.4	1.5
Central 40 Solar	40.0	53.8	1.4
Friant 1	25.0	24.1	0.6
Quinten Luallen (Friant 2)	7.3	28.4	0.7
Santa Clara Tioga Canopy	0.4	0.5	0.0
Joint Power Agencies[2]			
NCPA			
Geothermal Project	55.7	337.4	8.5
Combustion Turbine Project	31.0	6.1	0.2
Lodi Energy Center Project	77.9	319.9	8.1
Hydroelectric Project	93.6	70.6	1.8
M-S-R PPA			
Big Horn I Wind Energy	105.0	297.8	7.5
Big Horn II Wind Energy	17.0	46.5	1.2
Market Purchases	0.0	1,116.9	28.2
Total[6]	1,043.1	3,956.5	100.0%

(1) Rated or name-plate capacities.
(2) Capacity available represents entitlements, firm allocations and contract amounts.
(3) Santa Clara purchased varying amounts of capacity from Western Area Power Administration during the year.
(4) Columns may not add to totals due to rounding.

Source: City of Santa Clara.

Generating Facilities

Cogeneration. Santa Clara owns and operates a cogeneration plant which began operation in 1981. The cogeneration plant provides steam for sale to a paperboard plant within Santa Clara and delivers power to Santa Clara's electric distribution system. Santa Clara upgraded this plant to obtain a name-plate rating of 7.0 MW, effective July 1995. Fuel for the cogeneration plant (natural gas) is generally acquired under term contracts at prices fixed for the contract term. For the Fiscal Year ended June 30, 2021, the cogeneration plant generated 50.0 GWh of energy.

Stony Creek Hydroelectric System. Santa Clara owns and operates three hydroelectric plants consisting of (i) a 4.9 MW hydroelectric generating plant located at the United States Bureau of Reclamation Stony Gorge Dam near Willows, California, which was completed in 1985, (ii) a 6.2 MW hydroelectric generating plant located at the United States Army Corps of Engineers' Black Butte Dam near Orland, California, which was completed in late 1988, and (iii) a 0.53 MW hydroelectric generating plant located at the Orland Unit Water Users' Association High Line Canal/South Side Canal drop near the Black Butte dam, which was completed in late 1988. For the Fiscal Year ended June 30, 2021, the Stony Creek hydroelectric plants generated 5.3 GWh of energy.

Gianera Generating Station. Santa Clara owns and operates a nominal 49.5 MW dual fuel (natural gas and fuel-oil) combustion turbine generating plant consisting of two 24.75 MW units, which were completed in 1986 and 1987, respectively. This generation station is used to help meet Santa Clara's peak load and resource adequacy requirements. For the Fiscal Year ended June 30, 2021, the Gianera Generating Station generated 9.0 GWh of energy.

PG&E Grizzly Project. Pursuant to a 1990 settlement agreement with Pacific Gas and Electric Company ("PG&E"), Santa Clara agreed to finance and own 100% of a 20 MW hydroelectric facility (the "Grizzly Project") located on Grizzly Creek above the North Fork of the Feather River in Plumas County, California. The Grizzly Project operates in combination with the hydroelectric facilities of PG&E's Bucks Creek project. Pursuant to the settlement agreement, Santa Clara became a joint licensee in PG&E's Bucks Creek project. PG&E and Santa Clara are currently engaged in the process for re-licensing the project pursuant to FERC's integrated relicensing project. The construction of the Grizzly Project was financed (and refinanced) through the issuance by Santa Clara of electric system revenue bonds. Pursuant to the settlement agreement, PG&E constructed and operates the Grizzly Project, which was placed into operation in November 1993.

Until the date Santa Clara's ownership of the Grizzly Project is terminated (as described below), Santa Clara will own and receive all energy generated by the Grizzly Project, less transmission losses, as described in the settlement agreement, which reflects a contract capacity amount of 17.66 MW.

The Grizzly Project facilities include a tunnel intake structure, surge tank, steel penstock, powerhouse, turbine, transmission line (nominally rated at 115 kV) for interconnection with PG&E's transmission system, and certain additional switchyard equipment and related facilities. Annual energy generation of the Grizzly Project is estimated at 43.4 GWh in an average water year and 26.1 GWh in dry years. For the Fiscal Year ended June 30, 2021, the Grizzly Project generated 0.0 GWh of energy, which was due to the damage caused by the 2018 Camp Fire to the Caribou Palermo 115KV line that Grizzly is connected to. This transmission line is not expected to be re-connected until the end of 2023.

Pursuant to the settlement agreement, Santa Clara's interest in the Grizzly Project may revert to PG&E under certain limited circumstances. In the event of such reversion, Santa Clara will be reimbursed by PG&E for the fair market value of the project or be reimbursed for costs advanced by Santa Clara as provided in the settlement agreement. The earliest possible reverter date under the settlement agreement is November 18, 2027.

Donald Von Raesfeld Power Plant. Santa Clara constructed and placed into commercial operation on March 22, 2005, a 122 MW nominal/147.8 MW peak, natural gas-fired, combined cycle power plant known as the "Donald Von Raesfeld Power Plant" (initially designated by the Santa Clara City Council as the Pico Power Plant). The Donald Von Raesfeld Power Plant is located in an industrial area of Santa Clara, on the site of Santa Clara's Kifer Receiving Station. The Donald Von Raesfeld Power Plant includes its own switchyard, and connects to an existing 115 kV transmission line that currently crosses the plant site. Natural gas for the Donald Von Raesfeld Power Plant is delivered through an approximately two mile gas pipeline from the local transmission main of PG&E. For the Fiscal Year ended June 30, 2021, the Donald Von Raesfeld Power Plant generated 789.6 GWh of energy. Santa Clara has long-term agreements with EDF Trading North America and M-S-R Energy Authority ("M-S-R EA") in place for a significant portion of the plant's fuel requirements, and actively manages the quantity and price risks associated with fuel supply quantities not under long-term agreement. See "– Fuel Supply" below. Fully baseloaded, the Donald Von Raesfeld Power Plant could generate approximately 1,000 GWh of energy per year. However, Santa Clara substitutes market purchases when it is economical to do so.

Jenny Strand Solar Park. Santa Clara originally entered into an agreement with MiaSole, a California corporation, on December 6, 2011 for the purpose of having MiaSole donate one thousand (1,000) solar modules to Santa Clara at no cost to Santa Clara. On February 1, 2015, the original party "MiaSole" transferred ownership to MiaSole Hi-Tech Corp. MiaSole Hi-Tech Corp provided 1,121 solar modules to Santa Clara, at no cost to Santa Clara, to further Santa Clara's ability to provide renewable power. For the Fiscal Year ended June 30, 2021, Santa Clara received 0.2 GWh of energy from the solar modules.

Joint Powers Agency Resources

NCPA Geothermal Project. Santa Clara has purchased from NCPA, pursuant to power sales contracts, 54.65% and 34.13% entitlement shares, respectively, in the capacity of NCPA's Geothermal Project Plant 1 and Plant 2, and is obligated to pay 44.39% of the debt service and operating costs associated with such plants and steam field. The Geothermal Project power sales contracts are "take-or-pay" power sales contracts which require payments to be made whether or not the project is operable. Santa Clara's payments to NCPA under such power sales contracts, including debt service on NCPA's Geothermal Project revenue bonds, constitute an operating expense of Santa Clara's electric system. Each participant in NCPA's Geothermal Project is responsible under its power sales contracts for paying its capacity share of all of NCPA's costs of the Geothermal Project, including debt service on the NCPA Geothermal Project revenue bonds, and subject to a "step-up" obligation of up to 25% upon the unremedied default of another NCPA Geothermal Project participant. Santa Clara is currently taking delivery of its share of the capacity and associated energy from the Geothermal Project. Santa Clara's share of the current California Independent System Operator Corporation ("CAISO") maximum rated capacity of the project is 71.7 MW. For the Fiscal Year ended June 30, 2021, Santa Clara received 337.4 GWh of electric energy from the Geothermal Project. Current expectations are that the output from the plant will decrease gradually over time. These anticipated decreases are not material to Santa Clara's supply and can be replaced by additional short-term purchases, additional generation or reduced wholesale sales. For a further description of such resource, see "OTHER NCPA PROJECTS – Geothermal Project" in the front part of this Official Statement.

NCPA Combustion Turbine Project No. 1. Santa Clara has purchased a 25% entitlement share in NCPA's Combustion Turbine Project pursuant to a power sales contract with NCPA, which was amended to reflect that Santa Clara's 25% share comes specifically from the two Alameda plants and the one Lodi plant. Santa Clara uses this entitlement for resource adequacy purposes and to meet peak load requirements. Santa Clara delivers this entitlement to its electric system in accordance with CAISO tariffs. For the Fiscal Year ended June 30, 2021, Santa Clara received 6.1 GWh of electric energy from the Combustion Turbine Project. For a further description of such resource, see "OTHER NCPA PROJECTS – Combustion Turbine Project Number One" in the front part of this Official Statement.

NCPA Hydroelectric Project. Pursuant to a power sales contract (the "Third Phase Agreement" as referred to in the front part of this Official Statement), Santa Clara has purchased from NCPA a 37.02% entitlement share in NCPA's Hydroelectric Project (including a 1.16% entitlement share laid off to Santa Clara from the cities of Biggs and Gridley). The Hydroelectric Project power sales contract is a "take-or-pay" power sales contract which requires payments to be made whether or not the project is operable. Santa Clara's payment to NCPA under such power sales contract, including debt service on NCPA's Hydroelectric Project revenue bonds, constitute an operating expense of Santa Clara's electric system. Each participant in NCPA's Hydroelectric Project is responsible under its power sales contract for paying its entitlement share in the Hydroelectric Project of all of NCPA's costs of the Hydroelectric Project, including debt service on the NCPA Hydroelectric Project revenue bonds as well as a "step-up" of up to 25% in the event of the unremedied default of another project participant. Santa Clara is using its Hydroelectric Project entitlement to serve peak load and to provide capacity to support non-firm purchases of energy at market prices. Santa Clara receives this entitlement to its system by using transmission service available under its Metered Subsystem Agreement ("MSS Agreement") with the CAISO. For the Fiscal Year ended June 30, 2021, Santa Clara received 70.6 GWh of electric energy from the NCPA Hydroelectric Project. For a further description of such resource, see "THE HYDROELECTRIC PROJECT" in the front part of this Official Statement.

NCPA Lodi Energy Center. Pursuant to a power sales agreement (the "LEC Power Sales Agreement"), Santa Clara has purchased from NCPA a 25.75% generation entitlement share of the capacity and energy of the Lodi Energy Center on an unconditional take-or-pay basis, and is obligated to pay 25.75% of NCPA's Lodi Energy Center operating and maintenance expenses and 46.16% of the debt service for the Lodi Energy Center Revenue Bonds, Issue One. Santa Clara's obligations to make payments to NCPA under the LEC Power Sales Agreement are not dependent upon the operation of the Lodi Energy Center and are not subject to reduction. Upon an unremedied default by one Indenture Group A Participant (being all of the LEC Project Participants (as defined in the front part of this Official Statement) other than Modesto Irrigation District ("MID") and the California Department of Water Resources ("CDWR")) in making a payment required under the LEC Power Sales Agreement, the non-defaulting Indenture Group A Participants are required (except as lay-offs are made pursuant to the LEC Power Sales Agreement) to increase pro-rata their participation percentage by the amount of the defaulting Indenture Group A Participant's entitlement share, provided that no such increase can result in a greater than 35% increase in the participation percentage of the non-defaulting Indenture Group A Participants. Santa Clara receives this entitlement to its system by using transmission service available under its MSS Agreement with the CAISO. For the Fiscal Year ended June 30, 2021, Santa Clara received 319.9 GWh of electric energy from the Lodi Energy Center. For a further description of such resource, see "OTHER NCPA PROJECTS – Lodi Energy Center Project" in the front part of this Official Statement.

M-S-R PPA Purchased Power – Big Horn Project. Santa Clara, along with MID and the City of Redding ("Redding"), is a member of a California joint powers agency known as the M-S-R Public Power Agency ("M-S-R PPA"). In 2005, M-S-R PPA entered into a series of power purchase agreements with Avangrid Renewables LLC (formerly Iberdrola Renewables, Inc.) ("Avangrid"), certain of which agreements have been assigned to Avangrid's subsidiary, Big Horn I, LLC, for the purchase of energy from the Big Horn I wind energy project (the "Big Horn I Project") located near the town of Bickleton, in Klickitat County, Washington. The 199.5 MW project consists of 133 1.5 MW GE wind turbines. Santa Clara receives 52.5% of the power purchased by M-S-R PPA from the Big Horn I Project. Santa Clara's share equates to approximately a 105 MW share of the output at a cost comparable to combined cycle gas-fuel generation. Power deliveries commenced on October 1, 2006 and will continue through

September 30, 2026. Through an amendment of the original agreements M-S-R PPA has an obligation to continue to take the same output through September 30, 2031, or if the Big Horn Project is repowered M-S-R PPA will have a right of first offer to negotiate a long-term power purchase for such repowered project. The project interconnects with the high voltage transmission grid through an 11-mile transmission line at Bonneville Power Administration's ("BPA") Spring Creek Substation. Through the shaping and firming agreement between M-S-R and Avangrid, Avangrid receives Big Horn energy, as generated, and delivers such energy to M-S-R at the California-Oregon border pursuant to firm pre-established delivery schedules. Santa Clara uses a portion of its transfer capability of the COTP to provide for transmission of the output from the Big Horn I Project from the California-Oregon border. For the Fiscal Year ended June 30, 2021, Santa Clara received 297.8 GWh of energy from the Big Horn I Project.

The Big Horn Project is operated within the BPA balancing authority area. On October 1, 2009, BPA began imposing a wind integration charge for the purpose of recovering its costs to provide within-hour generation balancing services for wind generators. The wind integration charge is currently embodied in BPA's variable energy resource balancing service and the currently applicable wind integration charge is set at $1.22/kW-month. M-S-R PPA has entered into a series of amendments of the power purchase agreements with Avangrid whereby M-S-R PPA has agreed to pay, subject to certain caps and limitations, the first $1.20/kW-month of any wind integration charge imposed by BPA, Avangrid has agreed to pay the next $1.20/kW-month, and M-S-R PPA and Avangrid will equally split any wind integration charge exceeding $2.40 per/kW-month. Through a collaborative effort between Avangrid and M-S-R PPA, the Big Horn I Project has obtained California Renewable Portfolio Standard ("RPS") certification as an "Eligible" renewable resource by the California Energy Commission (the "CEC"). The Big Horn I Project has been registered with the Western Renewable Energy Generation Information System by Avangrid with BPA acting as the Qualified Reporting Entity. The RECs are transferred from Avangrid, the originator, to M-S-R PPA and finally to the members of M-S-R PPA, for either retirement or wholesale sales by such members.

M-S-R PPA subsequently negotiated a 25-year agreement with Avangrid for the purchase of the output from a 50 MW expansion of the Big Horn I Project, the Big Horn II Project. Santa Clara began receiving deliveries from the Big Horn II Project in November 2010. M-S-R PPA will pay the required wind integration charge and pay the cost of necessary transmission to BPA to deliver the output from the facility to a northern California market trading hub. Santa Clara receives 35% of the output from this project, or approximately 17.0 MW of project capacity. For the Fiscal Year ended June 30, 2021, Santa Clara received 46.5 GWh of energy from the Big Horn II Project.

M-S-R PPA – San Juan Retained Obligations. Santa Clara's resources acquired through M-S-R PPA previously included an entitlement to a portion of the output of M-S-R PPA's prior ownership interest in Unit No. 4 of the San Juan Generating Station (the "M-S-R PPA San Juan Unit No. 4 Interest"), a coal-fired steam electric generating unit located in San Juan County, New Mexico, which was constructed and is operated by Public Service Company of New Mexico ("PNM"). San Juan Unit No. 4 is one of four generating units that together make up the San Juan Generation Station. M-S-R PPA divested its ownership interest in San Juan Unit No. 4 in December 2017 but Santa Clara retains cost responsibility for its share of certain environmental and decommissioning obligations of M-S-R PPA in connection with this resource, which are described in more detail below.

M-S-R PPA purchased the 28.8% (approximately 146 MW) M-S-R PPA San Juan Unit No. 4 Interest on December 31, 1983. M-S-R PPA financed the acquisition of its M-S-R PPA San Juan Unit No. 4 Interest, and certain costs of related transmission arrangements, through the issuance of San Juan Project revenue bonds, of which $26.4 million principal amount was outstanding as of January 31, 2022. M-S-R PPA began dispatching power from the San Juan Ownership Interest in May 1995. Santa Clara purchased from M-S-R PPA, on a take-or-pay basis, a 35% entitlement share (approximately 51.1 MW of capacity and associated energy) in the M-S-R PPA San Juan Unit No. 4 Interest pursuant to a power sales agreement (the "M-S-R PPA Agreement"), among M-S-R PPA and its members. Santa Clara utilized its entitlement share of capacity and associated energy from the M-S-R PPA San Juan Unit No. 4 Interest from May 1995 through December 2017 either in its own system or for lay-offs or other transactions with third parties.

In July 2015, the M-S-R PPA Commission approved a number of agreements (the "San Juan Restructuring Agreements") between and among the San Juan Generation Station owners (the "San Juan Participants") to provide for the interests of M-S-R PPA and certain other San Juan Participants (the "Exiting Participants") in the San Juan Generation Station to be transferred to the remaining San Juan Participants effective December 31, 2017. In addition to the ownership divesture, the San Juan Restructuring Agreements provide for, among other things, the allocation of ongoing responsibility for decommissioning costs, mine reclamation costs and any environmental remediation obligations among the Exiting Participants and the remaining San Juan Participants, and the establishment and funding of mine reclamation and plant decommissioning trust funds. The San Juan Restructuring Agreements became effective on January 31, 2016 and the divestiture of M-S-R PPA's interests in San Juan Unit No. 4 was completed on December 31, 2017.

Pursuant to the San Juan Restructuring Agreements, M-S-R PPA and the other Exiting Participants retain certain liabilities for a share of the costs of San Juan Generation Station decommissioning and pre-exit date mine reclamation costs. Under the San Juan Restructuring Agreements, M-S-R PPA was required to maintain a balance of approximately \$15.9 million in the mine reclamation trust funds as of December 31, 2020 to fund its currently expected share of ongoing and final reclamation costs, which requirement has been met by a year-end balance of approximately \$17.2 million. In addition, under the San Juan Restructuring Agreements, M-S-R PPA will be required to maintain a balance of approximately \$2.3 million in the decommissioning trust fund as of December 31, 2022 to fund its currently expected share of the initial work for known asset removal and remediation activities in connection with decommissioning of the San Juan Generation Station. Funds currently on deposit in the decommissioning trust fund of approximately \$2.2 million plus interest earnings thereon, are expected to be sufficient to provide for such required balance. However, M-S-R PPA's final total proportionate share of San Juan Generation Station decommissioning and mine reclamation costs cannot yet be determined and will depend on a number of factors, including, among other things, the date the San Juan Generation Station is ultimately retired from service. Additional deposits to the trust funds may be required in the future if trust earnings are below expectations or if determined necessary by future decommissioning and reclamation costs study updates or applicable requirements (including, for example, if greenfield or brownfield restoration is determined to be required after final cessation of plant operations, which would significantly increase costs of remediation and restoration) and no assurance can be given that additional contributions will not be required from the M-S-R PPA members, including Santa Clara, to fund such amounts due.

Pursuant to the M-S-R PPA Agreement, Santa Clara is unconditionally obligated thereunder to pay its entitlement share of all of M-S-R PPA's costs associated with the M-S-R PPA San Juan Unit No. 4 Interest, including debt service on M-S-R PPA's San Juan Project revenue bonds which were issued to finance the acquisition of the M-S-R PPA San Juan Unit No. 4 Interest and any remaining liabilities for decommissioning and mine reclamation of the plant associated with the M-S-R PPA San Juan Unit No. 4 Interest. Santa Clara's payments to M-S-R PPA under the M-S-R PPA Agreement constitute an operating expense of Santa Clara's electric system. Santa Clara's obligations to make payments under the M-S-R PPA Agreement are not dependent upon the operation of the San Juan Unit No. 4 and are not subject to reduction. Pursuant to the M-S-R PPA Agreement, upon failure of any M-S-R PPA member to make any payment thereunder which failure constitutes a default under the M-S-R PPA Agreement, the participation percentage of each non-defaulting member automatically shall be increased for the remaining term of the M-S-R PPA Agreement in proportion to its participation percentage; provided, however, that the sum of such increase for any non-defaulting member shall not exceed 25% of its original participation percentage.

In light of the divesture of its active ownership interest in San Juan Unit No. 4, the majority of M-S-R PPA activities are currently related to renewables (including the Big Horn I and Big Horn II wind projects described above). Coordinating, regulatory, and compliance services costs are shared as follows: MID – 40%; Santa Clara – 40%; and Redding – 20%. Renewable administrative services, electric product, delivery and environmental attribute rights benefits and costs will be shared in accordance with contracted participation ratios.

See also "Indebtedness – Joint Powers Agency Obligations" below for information regarding Santa Clara's obligations in connection with bonds issued by the joint powers agencies in which it participates.

Purchased Power

Western Purchased Power. On December 14, 2000, Santa Clara signed a 20-year agreement with Western Area Power Administration ("Western") for the continued purchase of low-cost hydroelectricity generated from the Central Valley Project ("CVP"), replacing a prior agreement which expired December 31, 2004. The CVP, for which Western serves as marketing agency, is a series of federal hydroelectric facilities in Northern California operated by the United States Bureau of Reclamation. Service under the successor agreement began on January 1, 2005 and continues through December 31, 2024, with Santa Clara receiving a 9.06592% "slice of the system" allocation from Western. Effective April 1, 2015, Western reallocated shares and Santa Clara's base resource allocation increased to 9.60341%, which shall remain in effect until either superseded by another Exhibit A revision or termination of the agreement. The power marketed by Western to Santa Clara is provided on a take-or-pay basis where Western's annual costs are allocated to preference customers based on their CVP participation percentage. Western then allocates the annual take-or-pay charges to the preference customers based on a monthly percentage that is designed to reflect the anticipated seasonal energy deliveries. Santa Clara is obligated to its preference customer share of the costs associated with operating the CVP facilities. For the Fiscal Year ended June 30, 2021, Santa Clara received 202.6 GWh of energy from Western. On April 9, 2021, Santa Clara executed a 30-year agreement with Western for the continued purchase of hydroelectricity from the CVP, the term of which agreement begins on January 1, 2025 and continues through December 31, 2054 (unless earlier terminated). The agreement is similar to Santa Clara's existing contract with Western, but Santa Clara's base resource allocation decreases to 9.41134% beginning in 2025. In addition, in 2040, the Western customers' allocation of CVP will be reduced by 2% to allow for new Western customers. Under the new agreement, Santa Clara may reduce the CVP quantity or terminate the agreement when a new rate schedule is adopted or extended (at least every five years).

Manzana Wind. On February 14, 2012, Santa Clara entered into a 20-year power purchase agreement for 50 MW of the output from Avangrid's Manzana Wind Power Project in Kern County, California, which began power deliveries in December 2012. For the Fiscal Year ended June 30, 2021, Santa Clara received approximately 143.4 GWh of energy from the Manzana Wind Power Project.

G-2 Energy LLC – Wheatland Landfill. On June 19, 2007, Santa Clara entered into a power purchase agreement for energy from a 1.6 MW landfill gas facility, G2, near Wheatland, California. Santa Clara began taking delivery of energy from the G2 project in January 2009. For the Fiscal Year ended June 30, 2021, Santa Clara received 13.0 GWh of energy from the G2 project.

Ameresco. On February 12, 2008, Santa Clara entered into a 20-year purchase power agreement with Ameresco for landfill gas generated electricity from the closed municipal landfill located in the city limits of Santa Clara, which includes three microturbines, and is estimated to generate approximately 4,700 MWh per year during the first ten years of the contract and approximately 3,100 MWh per year during the final ten years of the contract. On May 25, 2010, Santa Clara entered into a second 20-year power purchase agreement with Ameresco for landfill gas generated electricity for 4.6 MW (and potentially up to 9.2 MW) from the Forward landfill in Manteca, California. This project became operational in February 2014. On August 17, 2010, Santa Clara entered into a third 20-year power purchase agreement with Ameresco for landfill gas generated electricity for up to 5 MW from the Vasco Road landfill near Livermore, California. The Vasco Road landfill project became operational in February 2014. For the Fiscal Year ended June 30, 2021, Santa Clara received approximately 2.2 GWh of energy from the initial Ameresco landfill project, and 32.5 GWh and 34.3 GWh for the Ameresco Forward landfill and Ameresco Vasco Road landfill projects, respectively.

Tri-Dam. In October 2013, Santa Clara entered into a power purchase agreement with the Tri-Dam Project and the Tri-Dam Power Authority to purchase the output from four hydroelectric power plants located on the Middle Fork of the Stanislaus River in Tuolumne County: the 72.0 MW Donnells Powerhouse, the 25.9 MW Tulloch Powerhouse, the 11.5 MW Beardsley Powerhouse, and the 16.2 MW Sandbar Powerhouse. Power deliveries from Donnells, Tulloch, and Beardsley commenced on January 1, 2014. Power deliveries from Sandbar commenced on January 1, 2017. The agreement is scheduled to terminate on December 31, 2023. For the Fiscal Year ended June 30, 2021, Santa Clara received 28.0 GWh from Beardsley, 137.8 GWh from Donnells, 103.6 GWh from Tulloch, and 32.3 GWh from Sandbar under this agreement.

Rio Bravo. In August 2019, Santa Clara entered into a power purchase agreement with the Olcese Water District to purchase the output from Rio Bravo, a 14 MW hydroelectric power plant located in Kern County. The agreement commenced on September 1, 2019 and is scheduled to terminate on August 31, 2024. The agreement may be extended for an additional five-year term upon mutual written consent. For the Fiscal Year ended June 30, 2021, Santa Clara received 11.3 GWh of energy from the Rio Bravo hydroelectric project.

Recurrent. On July 14, 2011, Santa Clara entered into a 25-year power purchase agreement for the entire output from the RE Rosamond One LLC project, a 20.0 net MW solar photovoltaic-powered project in Kern County, California, which became operational in December 2013. For the Fiscal Year ended June 30, 2021, Santa Clara received 59.4 GWh of energy from Recurrent.

Central 40 Solar. On July 17, 2017, Santa Clara has entered into a 20-year power purchase and sale agreement with Samsung, contracted as Central 40, LLC, to develop, own and operate a 40 MW solar PV project located in Stanislaus County. The project became operational in February 2021. For the Fiscal Year ended June 30, 2021, Santa Clara received 53.8 GWh of energy from the Central 40 solar project.

Friant Power Authority, Facility 1. Santa Clara has executed a power purchase agreement to purchase up to 68,000 MWh per year of electricity over the term of the agreement, from January 1, 2016 to August 31, 2032. Facility 1 consists of three existing run-of-river hydroelectric generating plants: the River Outlet (2 MW), the Friant-Kern (15 MW), and the Madera (8 MW). For the Fiscal Year ended June 30, 2021, Santa Clara received 24.1 GWh of energy from the Friant Power Authority, Facility 1.

Friant Power Authority, Facility 2. Santa Clara has executed a power purchase agreement to purchase the Net Electrical Output from Facility 2, a run-of-the river hydroelectric generating plant, Quinten Luallen Power Plant (7 MW), from July 10, 2012 to December 31, 2032. For the Fiscal Year ended June 30, 2021, Santa Clara received 28.4 GWh of energy from the Friant Power Authority, Facility 2.

Santa Clara Tioga Canopy. On February 2, 2012, Santa Clara entered into a 20-year power purchase agreement with Tioga Solar Santa Clara, LLC. The project is located on Santa Clara's multi-level parking structure on Tasman Drive in the City of Santa Clara. The nameplate capacity of the project is 389.76 kW. For the Fiscal Year ended June 30, 2021, Santa Clara received 0.5 GWh of energy from the solar canopy.

Aquamarine Westside Solar. On April 29, 2021, Santa Clara entered into a power purchase and sale agreement with Aquamarine Westside, LLC for three years. Pursuant to the agreement, Santa Clara has purchased 75 MW (a 30% share) of the total solar PV project, which is located in Kings County, California. The project became operational in September 2021. This agreement was not part of Santa Clara's portfolio for the Fiscal Year ended June 30, 2021.

South Feather River Hydroelectric. On December 6, 2021, Santa Clara entered into a power purchase agreement (via a "Third Phase Agreement" with NCPA), pursuant to which Santa Clara has purchased a 64.2% project participation share in the output of the South Feather Power Project. The project consists of four hydroelectric power plants: the 37.5 MW Forbestown Powerhouse, the 11 MW Kelly Ridge Powerhouse, the 13 MW Sly Creek Powerhouse and the 60 MW Woodleaf Powerhouse. The four plants that make up the South Feather Power Project are located across Butte, Plumas and Yuba counties on the South Fork of the Feather River and Slate Creek. Based on the average historical generation from the project, Santa Clara's project participation share of the generation output is expected to be approximately 245 GWh annually. On December 19, 2021, Santa Clara began receiving delivery of the project output. The term of the agreement ends on December 31, 2031. The term of the agreement shall automatically extend for an additional 10 years unless the seller provides written notice of termination to not automatically extend the term. This agreement was not part of Santa Clara's portfolio for the Fiscal Year ended June 30, 2021.

Future Power Supply Resources

Santa Clara commenced a re-power project with S-Power in 2016 at an existing Altamont Wind Project site owned by the City of Santa Clara. Rooney Ranch Wind LLC (originally Rooney Ranch LLC), a privately owned company created by S-Power ("Rooney Ranch"). Rooney Ranch entered into a ground lease agreement with Santa Clara to construct, own and operate a 19 MW capacity wind generation facility. Santa Clara also entered into a power purchase agreement with Rooney Ranch for the purchase of the output from the facility. Concurrent with the Rooney Ranch project agreements, Santa Clara also entered into a power purchase agreement with Sand Hill A (13 MW) and Sand Hill B (17.5 MW), which are also owned by S-Power, to purchase wind generation output from a separate wind generation re-power project located on adjacent land. In total, the re-power projects are expected to provide 49.5 MW of capacity. The projects were originally scheduled to be commercially operating by December 31, 2020 under a 25-year agreement. However, due to delays in permitting, the power purchase agreements were amended in 2021 with a new expected commercial operation date of December 31, 2022.

Due to Santa Clara's projected retail demand growth driven primarily from the industrial sector and secondarily from the commercial sector, and to replace existing renewable energy contracts that will expire in the future, Santa Clara is actively exploring new renewable energy projects for procurement. Santa Clara is scoping renewable energy projects in the near term to also make use of the investment tax credit and production tax credit eligibility. Santa Clara is beginning to explore options for the procurement of energy storage and is undergoing economic analysis to investigate the potential for cost-effective investments in energy storage.

Fuel Supply

Natural gas is the primary fuel and the primary variable operating cost of Santa Clara's cogeneration plants, Gianera Generating Station and Donald Von Raesfeld Power Plant. See "– Power Supply Resources – Generating Facilities" above. These plants can require delivery of up to 49,000 million British Thermal Units ("MMBtu") of natural gas per day, with current average daily requirements of 37,300 MMBtu per day. This fuel supply is delivered to Santa Clara through PG&E's natural gas pipeline system. Santa Clara has developed a comprehensive natural gas program to both manage supply and price volatility. This includes the procurement of a supply of natural gas at a discount from the monthly index price pursuant to a gas prepayment arrangement (described below), several long-term fixed price futures contracts for 15,000 MMBtu per day from 2022 to 2025, and a long-term fixed price contract for 5,000 MMBtu per days from 2022 to 2026. Excluding the M-S-R EA Gas Supply Agreement (described below) which is not a fixed rate contract, approximately 54% of gas needed for Santa Clara-owned generation is hedged for Fiscal Year 2021-22, and 56% of gas needed for Santa Clara-owned generation is hedged in Fiscal Year 2022-23 (based in each case on the projected gas-fired production for Santa Clara-owned generation facilities during such period).

M-S-R Energy Authority–Gas Prepay. The M-S-R PPA members have formed a joint power agency known as M-S-R EA. In 2009, Santa Clara participated in the M-S-R EA Gas Prepay Project. The M-S-R EA Gas Prepay Project provides, through a Gas Supply Agreement between M-S-R EA and Santa Clara, for a secure and long-term supply of natural gas of 7,500 MMBtu daily (or 2,730,500 MMBtu annually) through December 31, 2012, and 12,500 MMBtu daily (or 4,562,500 MMBtu annually) thereafter until September 30, 2039. The Gas Supply Agreement provides this supply at a discounted price below the monthly market index price (the PG&E Citygate index) over the 30-year term. M-S-R EA entered into a prepaid gas purchase agreement with Citigroup Energy, Inc. ("CEI") to provide this gas supply, and issued $500.2 million of its Gas Project Revenue Bonds to finance the prepayment for Santa Clara, of which $494.8 million were outstanding as of January 31, 2022. Under the terms of the Gas Supply Agreement, M-S-R EA will bill Santa Clara for actual quantities of natural gas delivered each month on a "take-and-pay" basis. Moreover, any default by CEI or the other participants in M-S-R EA's Gas Prepay Project, MID and Redding, is non-recourse to Santa Clara.

Transmission Resources

TANC California–Oregon Transmission Project. Santa Clara, together with fourteen other Northern California cities and districts and one rural electric cooperative, is a member, or associate member, of a California joint powers agency known as the Transmission Agency of Northern California ("TANC"). TANC, together with Redding, Western, two California water districts and PG&E (collectively, the "COTP Participants") own the California–Oregon Transmission Project ("COTP"), a 340-mile long, 1,600 MW, 500-kV AC transmission project between southern Oregon and central California. The COTP was placed in service on March 24, 1993, at an original cost of approximately $430 million. TANC financed its interest in the COTP through the issuance of California-Oregon Transmission Project Revenue Bonds, of which approximately $169.9 million principal amount of revenue bonds was outstanding as of January 31, 2022. See "– Indebtedness."

In April 2008, TANC purchased the COTP transmission assets (approximately 121 MW) of Vernon Light & Power of the city of Vernon, California ("Vernon"), one of the original owners of the COTP. Santa Clara participated in the acquisition of an increased share of transfer capability of the COTP in connection with the acquisition from Vernon by TANC. TANC utilized a combination of cash and the issuance of commercial paper (which was subsequently refunded with taxable fixed-rate bonds) to fund the acquisition of Vernon's COTP transmission assets (the "Vernon acquisition debt"). Santa Clara, as well as the other acquiring TANC members, began scheduling the acquired COTP transmission transfer capability on April 8, 2008.

Pursuant to Project Agreement No. 3 for the COTP (the "TANC Agreement"), TANC has agreed to provide to Santa Clara and 12 other members of TANC (the "TANC Member-Participants") a participation percentage of TANC's entitlement of COTP transfer capability. In return, each TANC Member-Participant has severally agreed to pay TANC a corresponding percentage of TANC's share of the COTP construction costs, including debt service on TANC's outstanding revenue bonds and other obligations issued by TANC to finance its ownership share of the COTP. A TANC Member-Participant's obligations to make payments to TANC are not dependent upon the operation of the COTP and are not subject to reduction. Upon an unremedied default by one TANC Member-Participant in making a payment required under the TANC Agreement, the non-defaulting TANC Member-Participants are required to increase pro-rata their participation percentage by the amount of the defaulting TANC Member-Participant's entitlement share, provided that no such increase can result in a greater than 25% increase in the participation percentage of the non-defaulting TANC Member-Participants.

Pursuant to the TANC Agreement, Santa Clara's participation percentage was 20.4745% of TANC's share of COTP transfer capability (approximately 278 MW net of third party layoffs of TANC). Effective July 1, 2014, Santa Clara laid-off 147 MWs of this entitlement to MID, Turlock Irrigation District and Sacramento Municipal Utility District ("SMUD") under a 25-year agreement. During the term of this agreement, the parties taking on the entitlement will assume responsibility for all associated debt service, operations and maintenance costs and all administrative and general costs. As a result of the layoff agreement, Santa Clara is currently responsible for paying approximately 10.01% of the operating and maintenance expenses of the COTP and approximately 9.81% of TANC's COTP debt service. Santa Clara remains contractually obligated for its full participation share. Santa Clara's payments to TANC under the TANC Agreement, including debt service on TANC's revenue bonds, constitute an operating expense of Santa Clara's electric system.

To utilize the full transfer capability of the COTP and the Intertie (described below) on a firm basis between the Pacific Northwest and California, it is necessary to coordinate the operation of all three transmission lines. The Pacific AC Intertie (the "Intertie") is a two line system which, like the COTP, connects California utilities with those in the Pacific Northwest. The Intertie lines are owned by PG&E, PacifiCorp and Western and are operated by the CAISO. Rate schedules are on file with the Federal Energy Regulatory Commission ("FERC") to accomplish this coordination. The three-line system comprised of the COTP and the Intertie is collectively referred to as the California-Oregon Intertie ("COI").

As the 340-mile COTP transmission line runs from Kamath County in Southern Oregon to the Tesla Substation located south of the City of Tracy in San Joaquin County, in central California, approximately 34% of the transmission line runs through the "elevated" Tier 2 fire risk zone and 1% runs through the "extreme" Tier 3 fire risk zone as identified on the CPUC's Fire Threat Map. TANC employs a fire risk management plan to mitigate its wildfire risk exposure that includes semi-annual aerial inspections; a series of annual ground inspections; a rigorous vegetation management program; as well as limiting crops and vegetation height in orchard areas. The COTP is constructed entirely of steel lattice towers or single pole steel structures which includes a 200 foot right-of-way for the majority of the COTP that is kept clear of trees and large vegetation. The COTP Member-Participants formed a wildfire committee to address ongoing compliance with recently enacted laws, strengthen existing practices, and monitor relevant legislative and regulatory activities. TANC has submitted its wildfire mitigation plan for the COTP to the California Wildfire Safety Advisory Board as required by California Senate Bill 901 ("SB 901"). See "CERTAIN FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY – State Legislation and Regulatory Proceedings – Legislation Relating to Wildfires; Related Risks" in the front part of this Official Statement.

Santa Clara is using a portion of its share of the project transfer capability of the COTP to provide transmission of energy generated from the Big Horn Projects (described under "– Power Supply

Resources – Purchased Power") and turning over Santa Clara's share of project transfer capability of the COTP to the CAISO in exchange for Congestion Revenue Rights and Congestion Revenue Rights revenues.

TANC Tesla–Midway Transmission Service. The southern physical terminus of the COTP is near PG&E's Tesla Substation near Tracy, California. The COTP is connected to Western's Tracy and Olinda Substations. PG&E provides TANC and certain of the TANC members with 300 MW of firm, bi-directional transmission service on its transmission system from its Midway Substation near Buttonwillow, California (the "Tesla-Midway Service") to those members under a long-term agreement known as the South of Tesla Principles. Santa Clara's share of Tesla–Midway Transmission Service is 81 MW. Santa Clara utilizes its share of the TANC Tesla–Midway Transmission Service to provide access to power supplies located in the southwest.

Geysers Transmission Project. Santa Clara is a participant in a double circuit 230 kV transmission line between Castle Rock Junction and PG&E's Lakeville substation with a combined rated capacity of 1,206 MW. There are four participants in this project (PG&E, with a 931 MW interest; CDWR, with a 165 MW interest; NCPA, with a 50 MW interest; and Santa Clara, with a 60 MW interest). Through a long-term layoff agreement with CDWR, Santa Clara has the ability to use an additional 31 MW of this transmission facilities' capacity for the life of the asset. CDWR has recently filed notice to terminate its participation in the project, but has yet to reach agreement with Santa Clara how to terminate their long-term layoff agreement.

Interconnections and Distribution Facilities

Santa Clara's service area is surrounded by a portion of PG&E's service area and the two systems are interconnected at two City-owned 115 kV receiving stations – Northern Receiving Station ("NRS") and Kifer Receiving Station ("KRS"), each located within the city limits. In addition, Santa Clara has a 230 kV interconnection with PG&E at PG&E's Los Esteros Substation ("LES") in the city of San Jose. Power received at LES is transmitted by Santa Clara approximately six miles to NRS. Santa Clara owns facilities for the distribution of electric power within its city limits (approximately 18.4 square miles), which includes approximately 31 miles of 60 kV power lines, approximately 560 miles of 12 kV distribution lines (approximately 67% of which are underground), and 29 stations. Santa Clara's electric system experiences approximately 1.3 hours of outage time per customer in 2021. This compares favorably with other utilities in California with reliability factors ranging from 1.0 to 2.5 hours outage per customer per year.

Historically, PG&E provided interconnection, partial power and other support services to Santa Clara under an interconnection agreement. Beginning March 31, 1998, the operation of the transmission facilities owned by California's investor-owned utilities, including PG&E, was undertaken by the CAISO. In July 2002, FERC approved a series of agreements between Santa Clara, PG&E, the CAISO and NCPA (which acts as scheduling coordinator for Santa Clara), including Santa Clara's MSS Agreement with the CAISO, to replace Santa Clara's interconnection agreement with PG&E and to allow Santa Clara to operate within the CAISO control area.

To the extent Santa Clara requires transmission/ancillary/power services beyond those contained in other remaining existing contracts or from Santa Clara's own generating resources, Santa Clara will procure such transmission/ancillary/power services from the CAISO or via the CAISO's markets.

Santa Clara is unable to predict how future industry changes, especially those concerning resource adequacy requirements, renewable fuels, greenhouse gas limitations and new transmission facilities to serve potential renewable energy projects, will affect future costs for the purchase of services under its interconnection, scheduling and CAISO agreements.

Renewable Energy and Energy Efficiency

A significant portion of the energy received by Santa Clara's electric customers is generated from renewable energy resources. Santa Clara's power mix in calendar year 2020 consisted of 32% eligible renewable resources. When large hydroelectric resources are included, Santa Clara's power mix consisted of 48% renewable and large hydroelectric power. On December 6, 2011, the Santa Clara City Council adopted revisions to Santa Clara's Environmental Stewardship and Renewable Portfolio Standard Policy Statement, and adopted a new RPS Enforcement Program, to conform to the standards and timetable set forth in California Senate Bill X1-2, signed by the Governor on April 12, 2011. Santa Clara satisfied the RPS target for Compliance Period 1 (from 2011 through 2013), with an average of approximately 20% of Santa Clara's energy portfolio supplied from renewable resources over such period, which has been verified and approved by the State of California. Santa Clara has satisfied the RPS target for Compliance Period 2 (from 2014 through 2016), meeting the compliance requirement of 20% of retail sales in 2014 and 2015, and 25% of retail sales in 2016. Santa Clara has also satisfied the RPS target for Compliance Period 3 (from 2017 through 2020), meeting the compliance requirement of 27% of retail sales in 2017, 29% of retail sales in 2018, 31% of retail sales in 2019, and 33% of retail sales in 2020. California Senate Bill 350 requires that the amount of electricity generated each year from eligible renewable energy resources be increased to at least 50% of total retail sales by December 31, 2030. In addition, Santa Clara is preparing to meet the accelerated eligible renewable energy compliance requirement of 60% of retail sales by December 31, 2030 in accordance with California Senate Bill 100. See "CERTAIN FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY – State Legislation and Regulatory Proceedings – *California Renewables Portfolio Standard*" in the front part of this Official Statement.

Santa Clara's energy efficiency programs are separated into residential and business programs, with the majority of funding toward its largest customer segment - the business sector. Total Public Benefits Charge funds are about $12 million per year. Residential programs include rate assistance for low-income customers, energy efficiency rebates (for example, clothes dryers, heat pump water heaters, and variable speed pool pumps), energy audits, and programs for schools and libraries. Business programs include energy audits, installation management for small companies, rebates for a wide variety of equipment (for example, lighting, air conditioning systems, chillers, motors, new construction, food service equipment and customized installations, etc.), and design and construction assistance.

Wholesale Energy

For a number of years, Santa Clara has used its energy and transmission resources together with its power scheduling capabilities to buy and sell energy in the western North American market. As deregulation unfolded, a greater need to manage resources on a day-to-day basis evolved, resulting in a more comprehensive approach to trading operations at Santa Clara. The principal reason for wholesale trading is to optimize the value of the utility's assets and cost-effectively serve its retail load. For the Fiscal Years ended June 30, 2020 and 2021, net trading revenues (wholesale power and fuel sales revenues less wholesale power and fuel purchase costs) were approximately $(5.1) million, and $10 million, respectively. The results in the Fiscal Year ended June 30, 2021 are primarily related to the expiration at the end of 2020 of a high priced long-term natural gas contract and long-term natural gas futures contracts Santa Clara entered in the early 2020 to hedge its long-term fuel costs. These fixed-priced futures purchase contracts were settled/sold at Intercontinental Exchange (Ice) at higher than the contract prices. See also "– Fuel Supply."

Risk Management

On December 5, 2006, the Santa Clara City Council approved an amended Risk Management Policy to provide policy guidance with respect to its wholesale power activities. Pursuant to the Policy, Santa Clara has established a Risk Oversight Committee (composed of the City Manager, the Director of

Finance, the Chief Electric Utility Officer and the Santa Clara City Attorney) and a Risk Management Committee, to oversee all proposed power purchase agreements, whether for retail or wholesale purposes. Pursuant to the Policy, Santa Clara has also established regulations approved by the Risk Oversight Committee to govern the various functions of its trading operations. The Policy and Regulations 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 Santa Clara's overall exposure balance or "book" and opportunities to internalize related transactions; and (e) develop an effective, streamlined ability to timely commit to transactions. The Regulations establish guidelines for, among other things, acceptable counterparty creditworthiness standards and requirements for limits on credit exposure to any individual counterparty. Most of the purchase and sale transactions entered into by the power trading operation are for 92 days or less.

Wildfire Mitigation Measures

Santa Clara owns a limited number of remote transmission assets, including, but not limited to, wires, poles, and other needed equipment to safely maintain and deliver power generated from generation assets located outside the city limits. Pursuant to the requirements of California Senate Bill 1028, the Santa Clara City Council made a wildfire risk determination at its October 9, 2018 City Council meeting and directed the electric utility to create a wildfire mitigation plan. The initial Silicon Valley Power Wildfire Mitigation Plan was adopted by City Council on June 25, 2019. Current wildfire mitigation practices include periodic inspection and maintenance, vegetation management and re-energization procedures in the event of a line trip. The California Wildfire Safety Advisory Board ("WSAB") issued the Guidance Advisory Opinion for the 2021 Wildfire Mitigation Plans of Electric Publicly Owned Utilities and Cooperatives ("2021 WSAB Guidance Advisory Opinion") on December 15, 2020. Santa Clara provided its 2021 informational response to the WSAB for each of the recommendations included in the 2021 WSAB Guidance Advisory Opinion which was presented to the Santa Clara City Council on June 8, 2021. Santa Clara updates its wildfire mitigation plan on an annual basis, with comprehensive review required every three years. See also "CERTAIN FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY – State Legislation and Regulatory Proceedings – Legislation Relating to Wildfires; Related Risks" in the front part of this Official Statement.

COVID-19

The spread of the novel strain of coronavirus (and variants thereof) and the disease it causes (now known as "COVID-19") has had significant negative impacts throughout the world, including in California. In 2020, the World Health Organization declared the COVID-19 outbreak to be a pandemic, and states of emergency have been declared by the United States, the State and numerous counties throughout the State. The purpose behind these declarations was to coordinate and formalize emergency actions across federal, state and local governmental agencies, and to proactively prepare for a wider spread of the virus.

On March 19, 2020, in an effort to slow the spread of COVID-19, Governor Newsom issued Executive Order N-33-20 ordering individuals living in the State to stay home or at their place of residence except for specified exceptions, including exceptions for certain sectors of the workforce that were classified as providing essential services and products, which allowed businesses and workers in such sectors to continue to operate on-site operations while Executive Order N-33-20 was effective. On June 11, 2021, Governor Newsom issued two executive orders, which became effective on June 15, 2021, which had the effect of rescinding a majority of the COVID-19-related restrictions and providing a timeline for gradually lifting certain of the other restrictions that were not fully rescinded on June 15, 2021.

During the pandemic, Santa Clara has experienced a decline in electricity demand by the commercial sector while electricity usage by the residential sector increased, as might be expected with many retail establishments being closed and people staying home. An overall increase in energy consumption of approximately 181 GWh experienced by Santa Clara in Fiscal Year 2020-21 was driven by Santa Clara's large industrial sector customers, many of which are Data Center and Semiconductor related businesses For information regarding Santa Clara's load requirements over the past five Fiscal Years, see "– Power Supply Resources." For information regarding the types of businesses comprising the Electric System's largest customers, see "– Major Customers." See also "Customers, Energy Sales, Revenues and Demand."

Historically, Santa Clara's annual write-offs for uncollectible accounts have been less than 0.01% of gross billings of the Electric System. Since the onset of the COVID-19 pandemic, write-offs for uncollectible accounts has increased to approximately 0.02% of gross billings for Fiscal Year 2020-21. To help mitigate the economic impact of COVID-19 and the related governmental regulations on its customers, Santa Clara implemented a payment deferral program for all customers of Santa Clara utilities, which included the suspension of the disconnection of services by City utilities for non-payment of utility bills since March 13, 2020, and the date that disconnections may resume has not been established. In additional to the suspension of late payment penalties, numerous programs have been implemented for payment assistance. These programs include Long-Term Rate Assistance, Payment Arrangements, Help Your Neighbor Program, and a one-time $30 Energy Efficiency credit to all residential accounts.

Santa Clara was allocated approximately $1.3 million under the California Department of Community Services and Development California's Arrearage Payment Program ("CAPP"), to aid the accounts that have fallen behind during the period of May 4, 2020 through June 15, 2021. Santa Clara is expected to receive the funding in February 2022.

With widespread vaccination currently underway in the United States and many countries worldwide, governmental-imposed stay-at-home orders and restrictions on operations of schools and businesses implemented to respond to and control the outbreak have been eased or eliminated. However, restrictions may be re-imposed in various jurisdictions from time to time as local conditions warrant. Santa Clara cannot predict whether any reinstatement or expansion of stay-at-home orders and travel or other restrictions will occur or when a full resumption of all economic activity will be achieved. The ultimate impact of COVID-19 on the operations and finances of Santa Clara or the Electric System is unknown and there can be no assurances that COVID-19 will not materially adversely impact the financial condition of Santa Clara or the Electric System in the future. There are many variables that will continue to contribute to the economic impact of the COVID-19 pandemic and the recovery therefrom, including the length of time social distancing measures are in place, the effectiveness of State and federal government relief programs and the timing for containment and treatment, new coronavirus strains, vaccinations efforts and vaccine hesitancy. Santa Clara cannot predict the extent or duration of such impacts.

Rates and Charges

The Santa Clara City Council is authorized by the City Code of the City of Santa Clara to set charges, pay for and supply all electric energy and power to be furnished to customers according to such schedules, tariffs, rules and regulations as adopted by the City Council. The authority of Santa Clara to impose and collect rates and charges for electric power and energy is not presently subject to the regulatory jurisdiction of the California Public Utilities Commission ("CPUC") or any other regulatory authority.

The following table summarizes a history of Santa Clara's electric rate increases over the last five years.

CITY OF SANTA CLARA
ELECTRIC UTILITY DEPARTMENT
HISTORY OF ELECTRIC RATE CHANGES

Date	Percent Change
January 1, 2022	3.0%
February 1, 2021	3.0
January 1, 2020	3.0
January 1, 2019	2.0
January 1, 2018	0.0

Source: City of Santa Clara.

Santa Clara has a monthly billing system set up for all its electric accounts. Charges for electric service are typically included in a customer's Municipal Utilities Regular Bill with other utility charges for the same time period. Bills are due and payable upon receipt of billing and generally become delinquent if not paid within 21 days thereafter. Late charges begin to accrue the day following the past due date. Electric service may be discontinued for nonpayment of any undisputed bill, following issuance by Santa Clara to the customer of a Shut-Off Notice Bill (typically the next bill sent to the customer following the past due bill) and a 48-Hour Notice of Service Discontinuance. Service will be restored only upon payment, in cash or certified funds, of all amounts then due and payable, including required deposits, utility service charges, and other related charges as permitted in the schedule of fees established and adopted by resolution of the Santa Clara City Council.

Major Customers

The ten largest customers of Santa Clara's electric utility department, in terms of kWh sales for the Fiscal Year ended June 30, 2021, which are listed below, accounted for 62.1% of total kWh sales and 55.7% of retail revenues. The largest customer accounted for 23.2% of total kWh sales and 22.8% of total retail revenues, while the smallest customer of the largest ten customers accounted for 2.4% of total kWh sales and 2.5% of total retail revenues. Santa Clara is heavily dependent upon its industrial customers, which comprise approximately 90.2% of its load and 88.5% of its revenues (in the Fiscal Year ended June 30, 2021). For reference, Santa Clara's industrial category includes all customers using more than 8,000 kWh per month. For many years, Santa Clara has been home to a number of the world's best known "high tech" firms involved in the design and production of computers and software. In the past few years, some of these firms have shifted production away from Santa Clara; however, this shift has been more than offset by the development of numerous data centers established to serve the data needs of corporate offices and of internet-related businesses.

To help retain its industrial customers, and thus assure the stability of Santa Clara's electric sales and revenue, Santa Clara has historically entered into multi-year electric service agreements with a number of its larger customers. Santa Clara has adopted flexible, standardized rate tariffs to replace these individually negotiated electric service agreements to facilitate transparency and efficiency. The new rate tariffs took effect on January 1, 2019 and have been implemented for all contract customers as their electric service agreements expired. These standardized rate tariffs have resulted in similar rate impacts for customers who meet specific criteria.

CITY OF SANTA CLARA
ELECTRIC UTILITY DEPARTMENT
MAJOR CUSTOMERS

Customer	Business
Air Products	Industrial Gas and Chemicals
Coresite Coronado Stender LLC	Data Centers
Cyxtera Data Centers Inc.	Data Centers
Digital Realty Trust LP	Data Centers
Intel Corporation	Semiconductors
Nvidia Corporation	Computer-Software Developers
Oracle America Inc.	Database Software Products
Owens Corning Sales LLC	Manufacturing
Quality Technology Services	Data Centers
Vantage Data Centers LLC	Data Centers

Source: City of Santa Clara.

Customers, Energy Sales, Revenues and Demand

The average number of customer accounts, kWh sales and revenues derived from sales, by classification of service, and peak demand during the past five Fiscal Years, are listed below.

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CITY OF SANTA CLARA
ELECTRIC UTILITY DEPARTMENT
CUSTOMERS, SALES, REVENUES AND DEMAND
(Fiscal Year Ended June 30)

	2017	2018	2019	2020	2021
Average Monthly Number of Customers Accounts:					
Residential	46,305	46,807	47,590	49,049	50,346
Commercial	6,231	6,156	6,522	6,681	6,762
Industrial	1,652	1,666	1,828	1,822	1,739
Other	549	569	551	446	344
Total	54,737	55,198	56,491	57,998	59,191
Kilowatt-hour Sales (000):					
Residential	228,505	229,957	230,901	240,247	268,601
Commercial	95,050	92,869	89,873	88,362	87,235
Industrial	3,133,903	3,236,317	3,241,566	3,327,560	3,478,492
Other	18,042	18,922	18,431	17,925	18,353
Total	3,475,500	3,578,065	3,580,771	3,674,094	3,852,680
Charges from Sale of Energy (000)(1):					
Residential	$ 27,635	$ 28,333	$ 28,761	$ 30,059	$ 33,566
Commercial	15,868	15,678	15,319	15,473	15,587
Industrial	352,973	370,696	370,740	387,486	396,968
Other	2,448	2,565	4,559	4,106	2,021
Total(2)	$398,924	$417,272	$419,379	$437,124	$448,143
Peak Demand (MW)	568.1	586.6	587.8	579.3	593.1

(1) Differs from Operating Revenues in Financial Operating Results and Balance Sheet information due to: (i) timing differences in accruals and billings; and (ii) exclusion of non-consumption based revenues.
(2) Includes public benefits charge and grid management charge revenues.

Source: City of Santa Clara

Service Area

Population. The service area of the Santa Clara electric utility is coterminous with Santa Clara's boundaries. Santa Clara is located at the southern end of the San Francisco Bay. Encompassing a total area of approximately 18.4 square miles within northern Santa Clara County, Santa Clara is situated in the heart of "Silicon Valley." Shown below is certain population data for Santa Clara, the County of Santa Clara and the State of California.

POPULATION

	City of Santa Clara	County of Santa Clara	State of California
1970	86,118	1,065,313	19,971,069
1980	87,700	1,295,071	23,667,764
1990	93,613	1,497,577	29,760,021
2000	102,361	1,682,585	33,871,653
2010	116,468	1,781,642	37,253,956
2011	118,794	1,806,087	37,561,624
2012	119,988	1,834,926	37,924,661
2013	121,459	1,863,975	38,269,864
2014	122,141	1,887,079	38,556,731
2015	122,442	1,911,670	38,865,532
2016	124,060	1,928,438	39,103,587
2017	123,975	1,937,008	39,352,398
2018	126,374	1,943,579	39,519,535
2019	125,908	1,944,733	39,605,361
2020	127,301	1,945,166	39,648,938
2021	130,746	1,934,171	39,466,855

Source: 1970-2010, as of April 1, based on historical U.S. Census population data compiled by the California State Department of Finance. 2011-2021, as of January 1, State of California, Department of Finance, E-4 Population Estimates for Cities, Counties and the State, with 2010 Census Benchmark. Sacramento, California, May 2021.

Employment. The main businesses in Santa Clara are manufacturing and industrial. There are numerous companies that manufacture electronic components, communications equipment, computer systems, electronic games and similar products, and general items such as fiberglass, paper and chemicals. As shown in the following table, these firms are among the largest employers in Santa Clara as of June 30, 2021.

CITY OF SANTA CLARA
TEN LARGEST EMPLOYERS

Employer	Business	Number of Employees
Applied Materials, Inc.	Nano Technology Mfg Services	8,500
Intel Corporation	Semiconductor Devices (Mfg.)	7,801
Advanced Micro Devices Inc.	Semiconductor Devices (Mfg.)	3,000
California’s Great America	Amusement Park	2,500
Nvidia	Software	2,500
Dell	Computers	2,088
Santa Clara University	Higher Education	2,000
City of Santa Clara	Local Government	1,783
Kaiser Foundation Hospitals	Healthcare	1,459
Macy’s	Retail	1,200

Source: City of Santa Clara Annual Comprehensive Financial Report for Fiscal Year 2021.

Due to the nature of local industry, with its heavy emphasis on electronics, aerospace and research, Santa Clara has attracted many professional people and industrial workers possessing skills well above the average.

The San Jose Labor Market, as defined by the State Employment Development Department, includes all cities within Santa Clara County. According to the California Employment Development Department, the County of Santa Clara's unemployment rate was 5.9% for the year 2020. The following table sets forth certain information regarding employment in the City of Santa Clara from 2016 through 2020.

CITY OF SANTA CLARA
CIVILIAN LABOR FORCE, EMPLOYMENT AND UNEMPLOYMENT
2016 TO 2020(1)(2)

	2016	2017	2018	2019	2020
Civilian Labor Force	68,800	69,600	71,200	71,800	69,800
Employment	66,400	67,400	69,400	70,200	65,600
Unemployment	2,500	2,100	1,800	1,600	4,100
Unemployment Rate	3.6%	3.1%	2.8%	2.3%	5.9%

(1) Annual averages; not seasonally adjusted. Data may not add due to rounding. Unemployment rates calculated using unrounded data. Most recent full year information available.
(2) Reflects March 2019 benchmark.

Source: State of California Employment Development Department, Labor Market Information Division, Monthly Labor Force Data for Cities and Census Designated Places, Annual Averages – Revised.

Transportation. Santa Clara is served by the Bayshore Freeway (U.S. Highway 101), which runs southeast from San Francisco to Los Angeles and is the major freeway connecting San Francisco and San Jose; Interstate 880, which runs north/south connecting San Jose and Oakland and becomes State Highway 17 (south of Interstate 280) and continues into Santa Cruz with access to Monterey; and Interstate 280, which runs north/south to San Francisco and State Highway 82. These freeways link Santa Clara to all parts of northern California.

Air transportation is available at both the San Francisco International Airport, approximately 40 miles to the north, and the San Jose International Airport, two miles from downtown Santa Clara. Rail service is provided by Union Pacific Railroad, on a north/south track linking San Jose and San Francisco, and CalTrain commuter service to Gilroy and San Francisco. The Guadalupe Corridor Light Rail has 20 completed miles of track from the Santa Clara Convention Center to the San Jose Convention Center, stretching to South San Jose, Mountain View and Milpitas.

The Santa Clara Valley Transportation Authority operates several lines within the City of Santa Clara with connections to major cities in the San Francisco Bay area. Interstate bus service is available via Greyhound Bus and Peerless. Most major trucking firms serve Santa Clara in addition to numerous local carriers.

Educational Facilities. The Santa Clara Unified School District provides public schooling from kindergarten through high school in most of the City of Santa Clara. Small geographical areas in the southern city limits are served by the Campbell Union Elementary School District and the Cupertino Union Elementary School District.

Santa Clara is also the home of the oldest institution of higher education in the West, Santa Clara University. Santa Clara residents are also in close proximity to San Jose State University, Stanford University and Mission College, as well as other units of the Community College System.

Capital Requirements

Santa Clara expects net capital requirements for the current and next four Fiscal Years (2021-22 through 2025-26) to total approximately $245.9 million. Such improvements include distribution system improvements and replacements, including several new distribution substations and significant upgrades to its internal bulk distribution loops and distribution feeders. These distribution facilities are needed to meet increased capacity requirements of new and existing customers and are expected to be financed through a combination of load development fees, direct customer contributions, funds from Santa Clara's available cash reserves (described under "– Cash Reserves") and electric revenues. Santa Clara does not currently expect to issue new debt to finance its capital requirements.

Indebtedness

Santa Clara Electric Revenue Bonds. As of January 31, 2022, Santa Clara had outstanding senior lien electric revenue bonds ("Senior Electric Revenue Bonds") in the aggregate principal amount of $39.870 million, payable from net revenues of the electric system. Such outstanding Senior Electric Revenue Bonds are comprised of $4.545 million aggregate principal amount of Electric Revenue Refunding Bonds, Series 2013 A and $35.325 million aggregate principal amount of Electric Revenue Refunding Bonds, Series 2018 A.

In addition to the outstanding Senior Electric Revenue Bonds, Santa Clara has entered into three loan agreements (collectively, the "Loan Agreements") with Bank of America, N.A. ("BANA"), each providing for a direct loan from BANA to Santa Clara. Santa Clara's obligation to make repayment to BANA of each of the loans is evidenced by a subordinate electric revenue bond (collectively, the "Subordinate Electric Revenue Bonds") of Santa Clara, payable from net revenues of the electric system on a basis junior and subordinate to the payment of Santa Clara's outstanding Senior Electric Revenue Bonds. As of January 31, 2022, Santa Clara had outstanding $99.140 million aggregate principal amount of such Subordinate Electric Revenue Bonds. Certain terms of the Loan Agreements and related Subordinate Electric Revenue Bonds of Santa Clara are further described below.

Santa Clara entered into a Loan Agreement (2020-1), dated as of April 1, 2020 (the "2020-1 Loan Agreement") with BANA, and in connection therewith issued and delivered to BANA its $52.985 million principal amount of Subordinated Electric Revenue Refunding Bonds, Series 2020-1 (the "Subordinate 2020-1 Bonds"), all of which were outstanding as of January 31, 2022. The Subordinate 2020-1 Bonds mature on July 1, 2032 (subject to prior redemption), with the aggregate principal amount thereof payable in installments on July 1 of each of the years 2028 through 2032. The Subordinate 2020-1 Bonds currently bear interest at the rate of 1.36% per annum.

Santa Clara entered into a Loan Agreement (2020-2), dated as of April 1, 2020 (the "2020-2 Loan Agreement") with BANA, and in connection therewith issued and delivered to BANA its $34.315 million principal amount of Subordinated Electric Revenue Refunding Bonds, Series 2020-2 (the "Subordinate 2020-2 Bonds"), all of which were outstanding as of January 31, 2022. The Subordinate 2020-2 Bonds mature on July 1, 2028 (subject to prior redemption), with the aggregate principal amount thereof payable in installments on July 1 of each of the years 2023 through 2028. The Subordinate 2020-2 Bonds currently bear interest at a taxable rate of 1.31% per annum. Pursuant to the 2020-2 Loan Agreement, the interest rate on the 2020-2 Subordinate Bonds may be converted to the tax-exempt rate of 1.02% per annum on any business day during the period that begins on October 3, 2022 (or, if earlier, the first day (if any) on which the Subordinate 2020-2 Bonds may be converted to a tax-exempt obligation as a result of an amendment to section 149(d) of the Code), and ends on January 1, 2023, subject to the satisfaction of certain conditions precedent under the 2020-2 Loan Agreement, including, but not limited to, (a) Santa Clara shall have delivered to BANA an opinion of Bond Counsel to the effect that, as of the conversion date, interest on the Subordinate 2020-2 Bond is excludable from the gross income of the holder thereof for federal income tax purposes; and (b) Santa Clara and BANA shall have executed and delivered a Conversion Agreement substantially in the form attached to the 2020-2 Loan Agreement.

Santa Clara entered into a Loan Agreement (2020-3), dated as of April 1, 2020 (the "2020-3 Loan Agreement") with BANA, and in connection therewith issued and delivered to BANA its $16.720 million principal amount of Subordinated Electric Revenue Refunding Bonds, Series 2020-3 (the "Subordinate 2020-3 Bonds"), of which $11.840 million principal amount was outstanding as of January 31, 2022. The Subordinate 2020-3 Bonds mature on July 1, 2024 (subject to prior redemption), with the aggregate principal amount thereof payable in installments on July 1 of each of the years 2020 through 2024. The Subordinate 2020-3 Bonds bear interest at the rate of 0.58% per annum.

Under each of the Loan Agreements, upon a failure by Santa Clara to pay principal or interest of any of the related Subordinate Electric Revenue Bonds, a failure by Santa Clara to perform or observe its covenants, a default in other specified indebtedness or obligations of Santa Clara, certain acts of bankruptcy or insolvency, or other specified events of default (including if S&P shall have assigned a credit rating below "BBB–," or if any of Fitch, S&P or Moody's shall have downgraded its credit rating on Santa Clara's Senior Electric Revenue Bonds or parity debt to below "BBB" or "Baa2"), BANA has the right to accelerate (immediately in the case of certain bankruptcy or insolvency events or upon the acceleration of other specified indebtedness or obligations, or, depending on the event, not earlier than seven days after the occurrence, or for certain events, not earlier than 180 days' after the occurrence and only after at least 60 days' notice) and declare Santa Clara's obligation to repay the related Subordinate Electric Revenue Bonds and all other obligations of the City to BANA under the respective Loan Agreement then due and payable.

For the Fiscal Year ending June 30, 2021, Santa Clara's annual debt service on the outstanding Senior Electric Revenue Bonds and the Subordinate Electric Revenue Bonds totaled approximately $13.4 million. Assuming no future debt issuances, the annual debt service on such outstanding Senior Electric Revenue Bonds and Subordinate Electric Revenue Bonds is expected to increase to a high of $17.4 million in Fiscal Year 2023-24, declining to a low of approximately $12.1 million in Fiscal Year 2028-29.

Joint Powers Agency Obligations. As previously discussed, Santa Clara participates in several joint powers agencies, including TANC, NCPA, M-S-R PPA and M-S-R EA, which have issued indebtedness to finance the costs of certain projects on behalf of their respective project participants. Obligations of Santa Clara under its agreements with respect to TANC, NCPA and M-S-R PPA constitute operating expenses of Santa Clara's electric system payable prior to any of the payments required to be made on Santa Clara's Electric Revenue Bonds described above. Agreements with TANC, NCPA and M-S-R PPA 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. Certain of these agreements contain "step-up" provisions obligating Santa Clara to pay a share of the obligations of a defaulting participant. As described herein, Santa Clara also participates in M-S-R EA and has certain payment obligation in connection therewith which constitute operating expenses of Santa Clara's electric system. However, Santa Clara's payment obligation to M-S-R EA is with respect to actual quantity of natural gas delivered each month on a take-and-pay (rather than take-or-pay) basis. Responsibility for bond repayment is non-recourse to Santa Clara. See "– Fuel Supply—*M-S-R Energy Authority–Gas Prepay*" above.

Santa Clara's participation and share of debt service obligation (without giving effect to any "step-up" provisions) for the TANC, NCPA and M-S-R PPA projects in which it participates are shown in the following table.

CITY OF SANTA CLARA
ELECTRIC UTILITY DEPARTMENT
OUTSTANDING DEBT OF JOINT POWERS AGENCIES
(as of January 31, 2022)
(Dollar Amounts in Millions)

	Outstanding Debt[1]	**Santa Clara Participation[2]**	**Santa Clara Share of Outstanding Debt[1]**
M-S-R PPA			
San Juan Unit No. 4	$ 26.43	35.00%	$ 9.25
NCPA			
Geothermal Project	10.82	44.39	4.80
Calaveras Hydroelectric Project	223.25[3]	37.02[4]	82.65
Lodi Energy Center, Issue One	206.89	46.16	95.50
TANC			
COTP	169.95	9.65[5]	16.40
TOTAL[6]	$637.34		$208.60

(1) Principal only. Does not include obligation for payment of interest on such debt. Excludes M-S-R EA as described above.
(2) Participation based on actual debt service obligation. Participation obligation is subject to increase (in an amount up to a specified accumulated maximum above the original participation) upon default of another Participant.
(3) Includes approximately $85.2 million of hedged variable rate bonds,[which are expected to be refunded by the 2022 Bonds].
(4) Includes 1.16% additional share purchased from other NCPA participants. In addition, Santa Clara's actual payments represent approximately 37.90% of outstanding debt service as a result of credit to non-participating members with respect to a portion of the debt obligation.
(5) Excludes 10.4705% of Santa Clara's original 20.4745% participation share for which, as described herein, Santa Clara has entered into an agreement to layoff to other TANC Member-Participants for a term of 25 years. Santa Clara remains contractually obligated for its full participation share. Santa Clara's actual debt service obligation differs slightly from this percentage due to varying shares of certain series of TANC bonds relating to each TANC member-participant's taxable portion and each TANC member-participant's participation or non-participation in acquisition of assets from Vernon.
(6) Columns may not add to totals due to independent rounding.

Source: City of Santa Clara Electric Utility Department.

For the Fiscal Year ended June 30, 2021, Santa Clara's payment obligations under its agreements with the joint powers agencies aggregated approximately $33.3 million. Santa Clara's obligations to the joint powers agencies is expected to range between $7.1 million and $33.4 million through Fiscal Year 2039-40. This projection assumes that layoff agreements affecting expected obligations to be paid by Santa Clara remain effective for their full term and are performed by the parties thereto, that there are no future debt issuances, and that swap counterparties on interest rate hedges continue to perform (all of Santa Clara's variable rate joint powers agency debt obligations are hedged). Santa Clara manages the total amount of variable rate debt exposure for its electric utility (including both direct and joint powers agency debt), and, by policy, has targeted up to approximately 25% as the appropriate variable rate exposure. Unreimbursed draws under liquidity arrangements supporting joint powers agency variable rate debt obligations bear interest at a maximum rate substantially in excess of the current interest rates on such variable rate debt obligations. Moreover, in certain circumstances, the failure to reimburse draws on the liquidity agreements may result in the acceleration of scheduled payment of the principal of such variable rate joint powers agency obligations. To the extent a joint powers agency has entered into interest rate swap agreements for the purposes of substantially fixing the interest cost with respect to variable rate joint powers agency obligations, there is no guarantee that the floating rate payable to such joint powers agency pursuant to such interest rate swap agreements will match the variable interest rate on the associated variable rate joint powers agency debt obligations to which the respective interest rate swap agreement relates at all times or at any time. Under certain circumstances, the swap providers may be obligated to make payments to the joint powers agency under their respective interest rate swap agreement that is less than the interest due on the associated variable rate joint powers agency debt obligations to which such interest rate swap agreement relates. In such event, such insufficiency will be payable from the obligated joint powers agency members (a corresponding amount of which proportionate to its debt service obligations to such joint powers agency could be due from Santa Clara). In addition, under certain circumstances, each of the swap agreements is subject to early termination, in which event the joint powers agency could be obligated to make a termination payment to the applicable swap provider (a corresponding amount of which proportionate to its debt service obligations to such joint powers agency could be due from Santa Clara). The only currently outstanding interest rate swap agreement related to Santa Clara's variable rate joint powers agency debt obligations is the 2008 Series A Hydroelectric Swap which is expected to be terminated in connection with the issuance of the 2022 Bonds. See "PLAN OF REFUNDING" in the front part of this Official Statement.

Transfers to the General Fund

The Santa Clara City Charter provides that up to 5% of gross revenues (not including revenues from wholesale transactions) from the electric utility is paid to the Santa Clara General Fund each year as a contribution in lieu of taxes. Pursuant to the Charter, such amounts are to be made from the Electric Utility Enterprise Fund after the payment of debt service on Santa Clara's Electric Revenue Bonds.

The following table sets out the transfers from the electric utility to the Santa Clara General Fund for the last five Fiscal Years.

CITY OF SANTA CLARA
ELECTRIC UTILITY DEPARTMENT
TRANSFERS TO THE GENERAL FUND
(Dollar Amounts in Thousands)

Fiscal Year	Transfer Amount
2016-17	$21,117
2017-18	21,986
2018-19	21,304
2019-20	22,710
2020-21	24,548

Source: City of Santa Clara.

Employees

General. As of January 1, 2022, Santa Clara had approximately 205 budgeted employees for its electric utility department. All of these Electric Utility department employees are represented either by the International Brotherhood of Electrical Workers ("IBEW") or one of the other City employees' associations, in matters pertaining to wages, benefits and working conditions. The labor agreements with IBEW and with the Engineers of the City of Santa Clara expired in December 2021, and new agreements are currently under negotiation. Until the successor agreements are executed, the terms of the expired agreements will continue to govern. The current labor agreements with the City of Santa Clara Employees Association (the primary bargaining units for employees of the electric utility department) and the miscellaneous unclassified management employees will expire in December 2023 and December 2024, respectively. There have been no strikes or other union work stoppages at Santa Clara, including its electric utility department.

Pension Plans. Santa Clara's permanent employees, including those in the electric utility department, are covered by the California Public Employees Retirement System ("CalPERS"), an agent multiple-employer defined benefit plan administered by CalPERS, which acts as a common investment and administrative agent for participating public employers within the State. CalPERS issues a separate annual comprehensive financial report. Copies of the CalPERS annual financial report may be obtained from the CalPERS Executive Office, 400 Q Street, Sacramento, California 95814.

Santa Clara's defined benefit pension plans, the Miscellaneous Plan and Safety Plan, provide retirement and disability benefits, annual cost-of-living adjustments, and death benefits to plan members and beneficiaries for city employees. All permanent (full-time and part-time) and eligible "as-needed" hourly Santa Clara employees are required to participate in CalPERS. No employees assigned to the electric utility department participate in the Safety Plan.

The cost of the Miscellaneous Plan is funded through bi-weekly contributions from employees and from employer contributions by Santa Clara. The member employees' contribution rates are set by State statute and only change with significant contract amendments. The member contribution can be paid by the employee or by Santa Clara on the employee's behalf in accordance with applicable labor agreements. 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 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. Santa Clara 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. The employer contribution rates are established, and may be amended, by CalPERS.

The electric utility department is allocated its portion of Santa Clara's required contributions for the Miscellaneous Plan. This allocation is based on eligible employee wages.

The table below sets forth the electric utility department's allocated share of Santa Clara's required contributions to the Miscellaneous Plan for the five Fiscal Years 2016-17 through 2020-21. The amount budgeted for the electric utility department's allocated share of Santa Clara's estimated required contributions to such plan for Fiscal Year 2021-22 is $11,000,000.

	Miscellaneous Plan		
Fiscal Year Ended June 30	**Electric Utility Department Allocated Share**	**Total City Required Contribution Amount**	**Contributions as a % of Covered Payroll**
2017	$ 7,558,410	$21,613,984	30.32%
2018	8,832,102	25,256,224	33.45
2019	8,258,503	23,615,964	28.84
2020	9,365,958	28,987,800	32.42
2021	10,027,454	31,035,143	34.75

Source: City of Santa Clara.

Santa Clara'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, and these assumptions and contribution requirement are subject to changes implemented by CalPERS Board of Administration. On December 21, 2016, the CalPERS Board of Administration lowered the discount rate from 7.5% to 7.0% using a three year phase-in beginning with the June 30, 2016 actual valuations, and beginning with Fiscal Year 2017-18 CalPERS changed the employer contributions toward the plan's unfunded liability as dollar amounts instead of prior method of a contribution rate. The announcement on July 12, 2021 that CalPERS achieved a preliminary investment return of 21.3% for the period from July 1, 2020 through June 30, 2021 caused the CalPERS Board of Administration to lower CalPERS' discount rate from 7.0% to 6.8% on November 15, 2021 in accordance with a risk mitigation policy that was adopted in 2015, which calls for the discount rate to be lowered if returns exceed the then-current discount rate by two or more percentage points. Lowering the discount rate generally means that employers which contract with CalPERS to administer their pension plans will see increases in their normal costs and unfunded actuarial liabilities. The CalPERS Board of Administration may in the future further adjust certain assumptions used in the CalPERS actuarial valuations, which adjustments may increase Santa Clara's required contributions to CalPERS in future years. Accordingly, Santa Clara cannot provide any assurances that Santa Clara's required contributions to CalPERS in future years will not significantly increase (or otherwise vary) from any past or current projected levels of contributions.

Effective for Fiscal Year 2014-15, Santa Clara adopted Governmental Accounting Standards Board ("GASB") Statement No. 68 ("GASB No. 68"), affecting the reporting of pension liabilities for accounting purposes. Under GASB No. 68, Santa Clara 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 department's proportionate share of the Net Pension Liability of Santa Clara's Miscellaneous Plan for the measurement periods ended June 30, 2016 through June 30, 2020 (as reported in Santa Clara's audited financial statements as of the succeeding fiscal year). The electric utility department's proportion of the Net Pension Liability was based on a projection of the electric utility department's long-term share of contributions to the Miscellaneous Plan relative to the projected contributions of all funds of Santa Clara.

City of Santa Clara Electric Utility Department
Proportionate Share of the Net Pension Liability – Miscellaneous Plan

Measurement Date[(1)] (June 30)	Proportionate Share of the Net Pension Liability[(2)]	Electric Utility Enterprise Fund Share of the Net Pension Liability[(2)]	Share of Net Position as a % of Share of Total Pension Liability	Share of Net Pension Liability as a % of Its Covered Payroll
2016	34.97%	$84,615,916	62.18%	390.63%
2017	34.97	92,735,319	62.02	372.00
2018	34.97	94,238,259	62.97	356.86
2019	32.31	92,007,139	62.72	347.81
2020	32.31	98,396,395	61.90	340.61

(1) Measured using prior fiscal year annual actuarial valuation rolled forward to measurement date using standard update procedures.

(2) Reflects the electric utility department's share of City's Miscellaneous Plan Net Pension Liability of $241,967,166, $265,185,350, $269,483,153, $284,763,675 and $304,538,518 as of June 30, 2016, June 30, 2017, June 30, 2018, June 30, 2019 and June 30, 2020 measurement date, respectively.

Source: City of Santa Clara.

As of the June 30, 2020 measurement date, the city-wide Total Pension Liability for the Miscellaneous Plan was $799,410,972 and the Plan Fiduciary Net Position was $494,872,454, resulting in a city-wide Miscellaneous Plan Net Pension Liability of $304,538,518. In the June 30, 2019 actuarial valuation utilized for measuring the pension liability as of the June 30, 2020 measurement date, the Entry Age Normal Actuarial Cost Method was used. The actuarial valuation assumptions used for determining pension liabilities included (a) a 7.15% investment rate of return (net of pension plan investment and administrative expense); (b) projected salary increases that vary based on age and type of service; (c) an inflation component of 2.50% per year; (d) payroll growth of 2.75%; and (e) a discount rate of 7.15%.

Public Agencies Post-Employment Benefits Trust Program. In Fiscal Year 2016-17, the Santa Clara City Council approved a resolution creating the Public Agencies Post-Employment Benefits Trust Program (the "Program") to allow Santa Clara to pre-fund its pension obligation. The Program was established within the meaning of Section 115 of the Internal Revenue Code, as amended, and the Regulations issued thereunder, and is a tax-exempt trust under the relevant statutory provisions of the State. The Program provides Santa Clara with an alternative to depositing additional funds with CalPERS and provides for greater Santa Clara control over assets and portfolio management, while allowing Santa Clara to set aside additional funds towards future CalPERS costs. The Program is administered by Public Agency Retirement Services ("PARS"). As of June 30, 2021, the market value of Santa Clara's contributions to the Program (city-wide) was $33,143,723, including the electric utility department's portion of $6,808,996.

Retiree Health Benefits. Santa Clara's single-employer defined benefit Other Post Employment Benefit ("OPEB") Plan Trust Fund, which was established by the Santa Clara City Council in Fiscal Year 2007-08 in accordance with GAAP, provides reimbursements to retirees for qualified healthcare expenses. Employees, including those assigned to the electric utility department, who have retired from Santa Clara with at least ten years of service and meet certain criterion based upon retirement date, household income in the most recent calendar year and age are entitled to reimbursements for qualified expenses. Annual maximum reimbursement amounts differ depending on when an employee retired from Santa Clara service. In Fiscal Year 2007-08, Santa Clara established an irrevocable exclusive agent multiple-employer defined benefit trust which is administered by Public Agency Retirement Services (PARS). The trust is used to accumulate and invest assets necessary to reimburse retirees.

The OPEB Plan trust annual contributions are based on actuarial valuations. The contribution requirements are established and may be amended by the Santa Clara City Council.

Effective for Fiscal Year 2017-18, Santa Clara 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 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.

The table below sets forth certain information regarding the electric utility department's allocated share of Santa Clara's annual contributions to the OPEB Plan trust for the for the four Fiscal Years 2017-18 through 2020-21, including the relation of such contributions to the actuarially determined contribution amount for such fiscal year. The amount budgeted for the electric utility department's share of OPEB Plan contributions for Fiscal Year 2021-22 is $634,943.

City of Santa Clara OPEB Plan
(dollar amounts in thousands)

Fiscal Year Ended June 30	Contribution Funded by Electric Utility Enterprise Fund	Actuarially Determined Contribution Amount by Electric Utility Enterprise Fund	Electric Utility Contribution Deficiency (Excess) to Actuarially Determined Contribution
2018[1]	$2,203	$1,911	$(292)
2019	1,876	1,856	(20)
2020	1,518	1,512	(6)
2021	1,465	1,559	94

Fiscal Year Ended June 30	Total City Contribution	Total City Actuarially Determined Contribution Amount	Total City Contribution Deficiency (Excess) to Actuarially Determined Contribution
2018	$6,300	$5,466	$(834)
2019	5,366	5,306	(60)
2002	4,696	4,681	(15)
2021[2]	4,535	4,826	291

(1) First fiscal year of implementation of GASB No. 75 for the electric utility enterprise fund.
(2) For the fiscal year ending June 30, 2021, the City's cash contribution was $3,361,417 in payment to the trust, $14,498 in administrative expenses paid outside of the trust, and the estimated implied subsidy was $1,159,257, for total contributions of $4,535,172.

Source: City of Santa Clara.

Pursuant to GASB No. 75, for the Fiscal Year ended June 30, 2021, Santa Clara reported a net OPEB liability of $11,860,957 for the Electric Utility Enterprise Fund's proportionate share (32.31%) of the City of Santa Clara's net OPEB liability of $36,710,000 (reflecting a total OPEB liability of $65,586,000 and a fiduciary net position of $28,876,000 for the OPEB Plan). The OPEB Plan Net Position as a percentage of Santa Clara's total OPEB liability was 44.00%. The net OPEB liability as a percentage of covered-employee payroll was 22.4%. The net OPEB liability was measured as of June 30, 2021 and the total OPEB liability used to calculate the net OPEB liability was determined by a June 30, 2020 actuarial valuation, rolled forward to June 30, 2021 using standard actuarial methods, based on actuarial methods and assumptions. In the June 30, 2020 actuarial valuation, the actuarial assumptions used in determining the total OPEB liability include (a) a 4.75% discount rate at June 30, 2021; (b) a 5.25% investment rate of return at June 30, 2020; (c) aggregate projected salary increases of 3.0% annually; (d) an inflation component of 2.75% per year; and (e) a healthcare cost trend of 7.0% for 2022, scaling down to 4.0% in year 2076 for Non-Medicare participants, 6.1% for 2022, scaling down to 4.0% in year 2076 for Medicare (Non-Kaiser) participants, and 5.0% for 2022, scaling down to 4.0% in year 2076 for Medicare (Kaiser) participants.

Additional information regarding the City of Santa Clara's retirement plans and other post-employment benefits can be found in the City of Santa Clara annual comprehensive financial report for the Fiscal Year ended June 30, 2021, which may be obtained at *http://santaclaraca.gov*.

Cash Reserves

Santa Clara maintains cash reserves for a number of reasons, including operating cash requirements, construction cash requirements, dealing with the cost impacts of dry hydroelectric conditions, gas and electric market volatility, and allowing Santa Clara the flexibility to increase rates on a scheduled basis. Santa Clara established a Cost Reduction Fund to manage the cost impacts of dry year hydroelectric conditions and gas and electric market volatility, as well as the scheduling of rate increases. As of December 31, 2010, the balance of the Cost Reduction Fund was transferred to the Rate Stabilization Fund (as a subaccount therein) described below.

Santa Clara has maintained a Rate Stabilization Fund (the "Rate Stabilization Fund"). Amounts in the Rate Stabilization Fund are available to pay costs of the electric utility subject to certain terms and conditions. As of June 30, 2021, approximately $157.7 million was on deposit in the Rate Stabilization Fund, including approximately $112.8 million on deposit in the Cost Reduction Account therein. In addition, as of June 30, 2021, Santa Clara had unrestricted operating cash reserves of approximately $151.8 million, and $125.4 million of cash reserves designated for construction purposes and approximately $6.8 million of cash reserves designated for pension liability and subsequently deposited at Public Agency Retirement Services. Thus, as of June 30, 2021, Santa Clara's electric system had restricted and unrestricted cash reserves totaling approximately $441.7 million.

Collectively, these reserves are designed to help insulate Santa Clara from market volatility. In addition, the indenture under which Santa Clara's Senior Electric Revenue Bonds were issued permits the use of certain unrestricted cash balances and reserves to satisfy Santa Clara's rate covenants with its bond holders. During the past five fiscal years, Santa Clara has not made transfers related to operating expenses from the Rate Stabilization Fund. For Fiscal Years 2016-17 and 2020-21. Santa Clara made deposits into the Rate Stabilization Fund in the amounts of $34.0 million and $33.8 million, respectively, as set forth below.

Fiscal Year	Transfer from Rate Stabilization Fund to Adjusted Net Revenues	Deposit to Rate Stabilization Fund
2016-17	--	$34,000,000
2017-18	--	--
2018-19	--	--
2019-20	--	--
2020-21	--	$33,789,186

Santa Clara has determined that it is appropriate to use a portion of its unrestricted cash balances and reserves to stabilize or subsidize its electric rates in the near term and to increase rates when appropriate. Santa Clara maintains a minimum target balance of $120 million for the Rate Stabilization Fund. See "– Condensed Operating Results and Selected Balance Sheet Information" and "– Rates and Charges" herein.

Insurance

The insurable property and facilities of the electric utility are covered under Santa Clara's general insurance policies. Santa Clara maintains property damage coverage through the Alliant Property Insurance Program ("APIP"), which has a plan limit of $800 million. Santa Clara maintains boiler and machinery property coverage for its power plants through APIP of $100 million per occurrence, with a $2,500 deductible per occurrence, with certain exceptions. Santa Clara does not carry earthquake insurance on the property and facilities of the electric utility except for a dedicated earthquake coverage of up to $20 million for the Grizzly Power Plant. Santa Clara maintains a dedicated flood limit shared by the power plants with limits of $27.5 million and $7.5 million for locations in Flood Zones A & V. Santa Clara is self-insured for up to $3 million for general liability claims. Inclusive of the self-insurance, Santa Clara has $25 million in liability coverage with CSAC Excess Insurance Authority. In addition, Santa Clara is also self-insured up to $750,000 per claim for workers' compensation claims with excess coverage up to the State of California statutory limit with employer's liability coverage of $5 million per claim (inclusive of Santa Clara's retention) through CSAC Excess Insurance Authority. All self-insurance programs are administered jointly by Santa Clara personnel and outside contractors.

Litigation

General. There is no action, suit or proceeding known to be pending or threatened, restraining or enjoining Santa Clara in the execution or delivery of, or in any way contesting or affecting the validity of any proceedings of Santa Clara taken with respect to Third Phase Agreement. At any given time, Santa Clara is party to or affected by various claims, disputes and litigation, including proceedings before FERC and other matters, that arise in the course of the electric system's activities and operations.

Present lawsuits and other claims against Santa Clara's electric utility are incidental to the ordinary course of operations of the electric utility and are covered by Santa Clara's liability coverage, including its self-insurance program. In the opinion of Santa Clara's management and, with respect to such litigation, the Santa Clara City Attorney, such claims and litigation will not have a materially adverse effect upon Santa Clara's ability to make payments under Third Phase Agreement.

Other Matters. In addition, from time-to-time, there are ongoing proceedings that involve projects in which Santa Clara has an interest and which comprise a portion of the current resource portfolio of Santa Clara's electric system. Although Santa Clara is generally not a party to such litigation, the outcome of such proceedings may impact the costs and operations of the affected project. Santa Clara is not aware of any such presently ongoing proceedings that, if determined adversely, would be expected to materially adversely affect the financial position or operations of its electric utility.

Condensed Operating Results and Selected Balance Sheet Information

The following table sets forth net income and selected balance sheet information of Santa Clara's electric utility for the five Fiscal Years ended June 30, 2021. The information for the Fiscal Years ended June 30, 2017 through June 30, 2021 was prepared by Santa Clara on the basis of its audited financial statements for such years.

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CITY OF SANTA CLARA
ELECTRIC UTILITY DEPARTMENT
SUMMARY OF FINANCIAL OPERATING RESULTS[(1)]
($ in 000s)

	2017	2018	2019	2020	2021
Summary of Income					
Operating Revenues[(2)]	$444,023	$453,869	$452,570	$483,048	$509,663
Operating Expenses:					
Salaries, Wages and Benefits	32,016	38,633	43,111	40,376	46,483
Materials, Supplies and Services[(3)]	341,536	369,739	334,447	384,784	376,753
Mandated Program Disbursement[(4)]	--	--	--	--	5,821
Depreciation	19,820	20,143	20,365	20,562	21,360
Total Operating Expenses	$393,372	$428,515	$397,923	$445,722	$450,417
Operating Income (Loss)	$ 50,651	$ 25,354	$ 54,647	$ 37,326	$ 59,246
Other Income[(4)]	11,868	15,321	31,231	36,658	17,179
Interest Expense	(8,697)	(8,103)	(11,723)	(6,859)	(3,744)
Gain (Loss) on Retirement of Fixed Assets	4,830	--	--	--	--
Equity (Loss) in Joint Power Agencies[(5)]	4,345	7,828	(10,159)	3,662	1,678
Net Income Before Operating Transfers and Extraordinary Items	$ 62,997	$ 40,400	$ 63,996	$ 70,787	$ 74,359
Selected Balance Sheet Information (as of June 30)					
Rate Stabilization Fund[(6)]	$120,959	$120,709	$123,947	$123,947	$157,736
Cash Designated for Construction	74,613	98,821	112,643	132,340	125,363
Cash Designated for Pension Liability	3,500	--	4,330	5,166	6,809
Operating Cash	83,325	99,237	117,611	126,464	151,778
Total Pooled & Cash Investments	$282,397	$318,767	$358,531	$387,917	$441,686

(1) Columns may not add to totals due to rounding.

(2) See "– Rates and Charges" above. Beginning in Fiscal Year 2020-21, Operating Revenues includes public benefit charge revenues, wholesale trading revenues and renewable energy credits as components of retail related revenue. Prior years' numbers shown above have been differ from those previously presented in order to conform with the presentation of Fiscal Year 2020-21.

(3) Includes purchased power payments and payments to joint power agencies. Beginning in Fiscal Year 2020-21, also includes additional costs of wholesale resources purchases. Prior years' numbers shown above have been differ from those previously presented in order to conform with the presentation of Fiscal Year 2020-21. Also includes payment of a portion of gross revenues to Santa Clara's General Fund as contribution in lieu of taxes which payment is subordinate to the payment of other operating expenses and debt service. Per the Santa Clara City Charter, up to 5% of gross revenues (not including revenues from wholesale transactions) from the electric utility is paid to Santa Clara's General Fund each year.

(4) Beginning in Fiscal Year 2020-21, Other Income includes interest income, rents, and other non-recurring miscellaneous income. Prior years' numbers shown above have been differ from those previously presented in order to conform with the presentation of Fiscal Year 2020-21. Unrealized gains were included in Fiscal Year 2018-19 ($7.395 million) and 2019-20 ($8.352 million). Unrealized losses were included in Fiscal Years 2016-17 ($2.723 million), 2017-18 ($2.635 million) and 2020-21 ($4,791 million).

(5) In Fiscal Year 2020-21, Equity gain in Joint Power Agencies was mainly due to equity share of loss of NCPA of ($30 thousand) and equity share of gain of TANC of $1.7 million.

(6) Includes Cost Reduction Subaccount. As of December 31, 2010, the Cost Reduction Fund was transferred to the Rate Stabilization Fund (as a subaccount therein).

Source: City of Santa Clara.

Rate Covenant Compliance Under Electric Revenue Bond Indenture

The electric revenue bond indenture pursuant to which Santa Clara's Senior Electric Revenue Bonds are issued requires Santa Clara to produce electric utility revenues in each year such that Adjusted Net Revenues (as defined in the electric revenue bond indenture) will be sufficient to pay debt service on all Senior Electric Revenue Bonds and parity debt for such Fiscal Year. The electric revenue bond indenture permits amounts in the Rate Stabilization Fund to be used to satisfy the rate covenant. Santa Clara has elected to use such unrestricted funds for such purpose as described in "– Cash Reserves" above.

Santa Clara has satisfied its rate covenant in each year as shown below. In addition to operating expenses and debt service, the electric utility has other obligations which it is required to satisfy. Such obligations include payments in lieu of taxes as well as capital expenditures not otherwise financed with bond proceeds, which obligations are, in accordance with the Santa Clara City Charter, payable subordinate to the payment of debt service on the Electric Revenue Bonds and parity debt. Capital expenditures not financed with bond proceeds are funded from a variety of sources, including reserves, developer contributions and electric system revenues. See "– Cash Reserves."

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CITY OF SANTA CLARA
RATE COVENANT COMPLIANCE UNDER
ELECTRIC REVENUE BOND INDENTURE[1]
($ in 000s)

	Fiscal Year Ending June 30,				
	2017	**2018**	**2019**	**2020**	**2021**
Debt Service Coverage:					
Adjusted Revenues[2]	$353,328	$383,662	$414,975	$445,142	$501,414
Adjusted Operating Expenses[3]	315,340	346,825	331,141	368,162	407,627
Adjusted Net Revenue Available for Debt Service	$ 37,988	$ 36,837	$ 83,834	$ 76,980	$ 93,787
Debt Service on Senior Electric Revenue Bonds[4]	$ 15,612	$ 14,204	$ 19,963	$ 14,178	$ 11,064
Debt Service on Subordinate Electric Revenue Bond	798	4,108	4,106	4,625	2,727
Total Debt Service[5]	$ 16,410	$ 18,312	$24,069	$ 18,803	$ 13,791
Adjusted Revenues in Excess of Debt Service Requirements	$ 21,578	$ 18,524	$ 59,765	$ 58,177	$ 79,996
Debt Service Coverage Ratio - Senior Electric Revenue Bonds	2.43	2.59	4.20	5.43	8.48
Debt Service Coverage Ratio – Senior and Subordinate Bonds	2.31	2.01	3.48	4.09	6.80

(1) Numbers may not add due to rounding.
(2) Adjusted Revenue includes operating revenues and non-operating revenues, other income (excluding unrealized gains or losses and developer contributions), net wholesale transactions and renewable energy credits, and excludes any gain on retirement of fixed assets, and equity in joint powers agency projects accounted for on the equity method of accounting. Also includes Rate Stabilization Fund transfers related to operating expenses. In Fiscal Year 2016-17, a deposit was made into the Rate Stabilization Fund in the amount $34.0 million. See "– Rates and Charges" and "– Cash Reserves."
(3) Adjusted Operating Expenses include operating expenses (including joint powers agency obligation payments) and other expenses, less depreciation and amortization expense and contribution-in-lieu to the General Fund. Adjusted Operating Expenses do not include any loss on retirement of fixed assets or any loss on joint powers agency projects accounted for on an equity method of accounting basis.
(4) Includes net swap payments and letter of credit fees relating to variable rate electric revenue bonds (which variable rate electric revenue bonds were redeemed in December 2018).
(5) Excludes joint powers agency obligations, the costs of which are a component of adjusted operating expenses. See footnote (3).

Source: City of Santa Clara.

APPENDIX B

NCPA AUDITED FINANCIAL STATEMENTS
FOR THE FISCAL YEARS ENDED JUNE 30, 2021 AND 2020

The combined financial statements of Northern California Power Agency and Associated Power Corporations as of and for the years ended June 30, 2021 and 2020 have been audited by Baker Tilly US, LLP, independent auditors, as stated in their report. Baker Tilly US, LLP has not been engaged to perform and has not performed, since the date of its report included therein, any procedures on the financial statements addressed in such report. Baker Tilly US, LLP has also not performed any procedures relating to this Official Statement.

APPENDIX C

BOOK-ENTRY ONLY SYSTEM

The information in this Appendix C regarding DTC and its book-entry system has been obtained from DTC's website, for use in securities offering documents, and NCPA takes no responsibility for the accuracy or completeness thereof or for the absence of material changes in such information after the date hereof.

The Depository Trust Company ("DTC"), New York, New York, will act as securities depository for the 2022 Bonds. The 2022 Bonds will be issued as fully-registered securities, registered in the name of Cede & Co. (DTC's partnership nominee) or such other name as may be requested by an authorized representative of DTC. One fully-registered bond certificate will be issued for each maturity of each Series of the 2022 Bonds, each in the aggregate principal amount of such maturity and will be deposited with DTC.

DTC, the world's largest securities depository, is a limited-purpose trust company organized under the New York Banking Law, a "banking organization" within the meaning of the New York Banking Law, a member of the Federal Reserve System, a "clearing corporation" within the meaning of the New York Uniform Commercial Code, and a "clearing agency" registered pursuant to the provisions of Section 17A of the Securities Exchange Act of 1934. DTC holds and provides asset servicing for over 3.5 million issues of U.S. and non-U.S. equity issues, corporate and municipal debt issues and money market instruments (from over 100 countries) that DTC's participants ("Direct Participants") deposit with DTC. DTC also facilitates the post-trade settlement among Direct Participants of sales and other securities transactions in deposited securities, through electronic computerized book-entry transfers and pledges between Direct Participants' accounts. This eliminates the need for physical movement of securities certificates. Direct Participants include both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, clearing corporations and certain other organizations. DTC is a wholly-owned subsidiary of The Depository Trust & Clearing Corporation ("DTCC"). DTCC is the holding company for DTC, National Securities Clearing Corporation and Fixed Income Clearing Corporation, all of which are registered clearing agencies. DTCC is owned by the users of its regulated subsidiaries. Access to the DTC system is also available to others such as both U.S. and non-U.S. securities brokers and dealers, banks, trust companies and clearing corporations that clear through or maintain a custodial relationship with a Direct Participant, either directly or indirectly ("Indirect Participants"). DTC has a Standard & Poor's rating of AA+. The DTC Rules applicable to its Direct and Indirect Participants are on file with the Securities and Exchange Commission. More information about DTC can be found at www.dtcc.com.

Purchases of the 2022 Bonds under the DTC system must be made by or through Direct Participants, which will receive a credit for the 2022 Bonds on DTC's records. The ownership interest of each actual purchaser of each 2022 Bond ("Beneficial Owner") is in turn to be recorded on the Direct and Indirect Participants' records. Beneficial Owners will not receive written confirmation from DTC of their purchase. Beneficial Owners are, however, expected to receive written confirmations providing details of the transaction, as well as periodic statements of their holdings, from the Direct or Indirect Participant through which the Beneficial Owner entered into the transaction. Transfers of ownership interests in the 2022 Bonds are to be accomplished by entries made on the books of Direct and Indirect Participants acting on behalf of Beneficial Owners. Beneficial Owners will not receive certificates representing their ownership interests in the 2022 Bonds, except in the event that use of the book-entry system for the 2022 Bonds is discontinued.

To facilitate subsequent transfers, all 2022 Bonds deposited by Direct Participants with DTC are registered in the name of DTC's partnership nominee, Cede & Co. or such other name as may be requested by an authorized representative of DTC. The deposit of 2022 Bonds with DTC and their registration in the name of Cede & Co. or such other DTC nominee do not effect any change in beneficial ownership. DTC has no knowledge of the actual Beneficial Owners of the 2022 Bonds; DTC's records reflect only the identity of the Direct Participants to whose accounts such 2022 Bonds are credited, which may or may not be the Beneficial Owners. The Direct and Indirect Participants will remain responsible for keeping account of their holdings on behalf of their customers.

Conveyance of notices and other communications by DTC to Direct Participants, by Direct Participants to Indirect Participants and by Direct Participants and Indirect Participants to Beneficial Owners, will be governed by arrangements among them, subject to any statutory or regulatory requirements as may be in effect from time to time. Beneficial Owners of 2022 Bonds may wish to take certain steps to augment the transmission to them of notices of significant events with respect to the 2022 Bonds, such as redemptions, tenders, defaults and proposed amendments to the 2022 Bond documents. For example, Beneficial Owners of 2022 Bonds may wish to ascertain that the nominee holding the 2022 Bonds for their benefit has agreed to obtain and transmit notices to Beneficial Owners. In the alternative, Beneficial Owners may wish to provide their names and addresses to the registrar and request that copies of the notices be provided directly to them.

Redemption notices shall be sent to DTC. If less than all of the 2022 Bonds within a maturity are being redeemed, DTC's practice is to determine by lot the amount of the interest of each Direct Participant in such maturity to be redeemed.

Neither DTC nor Cede & Co. (nor any other DTC nominee) will consent or vote with respect to the 2022 Bonds unless authorized by a Direct Participant in accordance with DTC's MMI Procedures. Under its usual procedures, DTC mails an Omnibus Proxy to NCPA as soon as possible after the record date. The Omnibus Proxy assigns Cede & Co.'s consenting or voting rights to those Direct Participants to whose accounts the 2022 Bonds are credited on the record date (identified in a listing attached to the Omnibus Proxy).

Payments of principal of, premium, if any, and interest on the 2022 Bonds will be made to Cede & Co., or such other nominee as may be requested by an authorized representative of DTC. DTC's practice is to credit Direct Participants' accounts upon DTC's receipt of funds and corresponding detail information from NCPA or the Trustee, on payable date in accordance with their respective holdings shown on DTC's records. Payments by Participants to Beneficial Owners will be governed by standing instructions and customary practices, as is the case with securities held for the accounts of customers in bearer form or registered in "street name," and will be the responsibility of such Participant and not of DTC, nor its nominee, the Trustee, or NCPA, subject to any statutory or regulatory requirements as may be in effect from time to time. Payment of principal of, premium, if any, and interest to Cede & Co. (or such other nominee as may be requested by an authorized representative of DTC) is the responsibility of NCPA or the Trustee, disbursement of such payments to Direct Participants will be the responsibility of DTC and disbursement of such payments to the Beneficial Owners shall be the responsibility of Direct and Indirect Participants.

DTC may discontinue providing its services as securities depository with respect to the 2022 Bonds at any time by giving reasonable notice to NCPA or the Trustee. Under such circumstances, in the event that a successor depository is not obtained, 2022 Bond certificates are required to be printed and delivered.

NCPA may decide to discontinue use of the system of book-entry only transfers through DTC (or a successor securities depository). In that event, 2022 Bond certificates will be printed and delivered to DTC.

APPENDIX D

SUMMARY OF CERTAIN PROVISIONS OF THE INDENTURE

APPENDIX E

PROPOSED FORMS OF CONTINUING DISCLOUSRE AGREEMENTS

CONTINUING DISCLOSURE AGREEMENT
BY AND BETWEEN THE
NORTHERN CALIFORNIA POWER AGENCY
AND
U. S. BANK TRUST COMPANY, NATIONAL ASSOCIATION

This Continuing Disclosure Agreement (the "Disclosure Agreement"), dated April ___, 2022, is executed and delivered by the Northern California Power Agency and U.S. Bank Trust Company, National Association, as Dissemination Agent (the "Dissemination Agent") in connection with the issuance by Northern California Power Agency ("NCPA") of $__________ aggregate principal amount of Northern California Power Agency Hydroelectric Project Number One Revenue Bonds, 2022 Refunding Series A (the "2022A Bonds") and 2022 Taxable Refunding Series B Bonds (the "2022B Bonds" and together with the 2022A Bonds, the "2022 Bonds"). The 2022 Bonds were issued pursuant to an Indenture of Trust, dated as of March 1, 1985, as amended and supplemented, including as supplemented by the Twenty-Seventh Supplemental Indenture of Trust, dated as of April 1, 2022 , with respect to the 2022A Bonds, and by the Twenty-Eighth Supplemental Indenture of Trust, dated as of April 1, 2022, with respect to the 2022B Bonds (collectively, the "Indenture"), each by and between NCPA and U.S. Bank Trust Company, National Association, as the Trustee. NCPA and the Dissemination Agent covenant and agree as follows:

SECTION 1. Purpose of the Disclosure Agreement. This Disclosure Agreement is being executed and delivered by NCPA and the Dissemination Agent for the benefit of the Bondholders and Beneficial Owners of the 2022 Bonds and in order to assist the Participating Underwriters in complying with the Rule.

SECTION 2. Definitions. In addition to the definitions set forth in the Indenture, which apply to any capitalized term used in this Disclosure Agreement unless otherwise defined in this Section 2, the following capitalized terms shall have the following meanings:

"Annual Report" shall mean any Annual Report with respect to the 2022 Bonds provided by NCPA pursuant to, and as described in, Sections 3 and 4 of this Disclosure Agreement.

"Beneficial Owner" shall mean any person who has or shares the power, directly or indirectly, to make investment decisions regarding ownership of any 2022 Bonds (including without limitation persons holding 2022 Bonds through nominees, depositories or other intermediaries).

"Disclosure Representative" shall mean the any of the Chairman, the General Manager, the Assistant General Manager, Finance and Administrative Services/Chief Financial Officer, and the Treasurer-Controller of NCPA or his or her designee, or such other officer or employee as NCPA shall designate in writing to the Trustee from time to time.

"Dissemination Agent" shall mean U.S. Bank Trust Company, National Association, acting solely in its capacity as Dissemination Agent hereunder, or any successor Dissemination Agent designated in writing by NCPA and which has filed with the Trustee a written acceptance of such designation.

"EMMA System" shall mean the MSRB's Electronic Municipal Market Access System or such other electronic system designated by the MSRB.

"Financial Obligation" shall mean a (a) debt obligation; (b) derivative instrument entered into in connection with, or pledged as security or a source of payment for, an existing or planned debt obligation; or (c) guarantee of a debt obligation or any such derivative instrument; provided that "financial obligation" shall not include municipal securities as to which a final official statement (as defined in the Rule) has been provided to the MSRB consistent with the Rule.

"Listed Event" shall mean any of the events listed in Section 5(a) of this Disclosure Agreement.

"MSRB" shall mean the Municipal Securities Rulemaking Board, or any successor thereto.

"Participating Underwriters" shall mean the original underwriters of the 2022 Bonds required to comply with the Rule in connection with the offering of the 2022 Bonds.

"Rule" shall mean Rule 15c2-12(b)(5) adopted by the SEC under the Securities Exchange Act of 1934, as the same may be amended from time to time.

"SEC" shall mean the United States Securities and Exchange Commission.

SECTION 3. Provision of Annual Reports.

(a) With respect to the 2022 Bonds, NCPA shall, or shall cause the Dissemination Agent to, not later than 180 days after the end of each fiscal year of NCPA (which presently ends on June 30), commencing with the report for the Fiscal Year ending June 30, 2022, provide to the MSRB through the EMMA System, in an electronic format and accompanied by identifying information all as prescribed by the MSRB, an Annual Report which is consistent with the requirements of Section 4 of this Disclosure Agreement. The Annual Report may be submitted as a single document or as separate documents comprising a package, and may include by reference other information as provided in Section 4 of this Disclosure Agreement; provided, that the audited financial statements of NCPA may be submitted separately from the balance of the Annual Report and later than the date required above for the filing of the Annual Report if they are not available by that date. If the fiscal year changes for NCPA, NCPA shall give notice of such change prior to the next date by which NCPA otherwise would be required to provide its Annual Report pursuant to this Section and in the manner provided for giving notices under Section 5 hereof.

(b) Not later than fifteen (15) business days prior to the date specified in paragraph (a) of this Section 3 for providing the Annual Report to the MSRB, NCPA shall provide its Annual Report to the Dissemination Agent. If by such date, the Dissemination Agent has not received a copy of the Annual Report from NCPA, the Dissemination Agent shall contact NCPA to determine if NCPA is in compliance with paragraph (a) of this Section 3.

(c) If the Dissemination Agent is unable to verify that an Annual Report has been provided to the MSRB by the date required in paragraph (a) of this Section 3, the Dissemination Agent shall send a notice to the MSRB through the EMMA System in substantially the form attached hereto as Exhibit A.

(d) Upon the provision by the Dissemination Agent of any Annual Report to the MSRB pursuant to paragraph (a) of this Section 3, the Dissemination Agent shall deliver a confirmation in writing to NCPA certifying that the Annual Report has been provided to the MSRB pursuant to this Disclosure Agreement and stating the date it was provided.

SECTION 4. Content of Annual Reports. NCPA's Annual Report shall contain or include by reference the following:

(i) A summary of the peak generating capability of the Project for the prior Fiscal Year;

(ii) A summary of the average generating capability of the Project for the prior Fiscal Year;

(iii) A summary of total energy generated with respect to the Project for the prior Fiscal Year; and

(iv) The audited financial statements of NCPA for the prior Fiscal Year, prepared in accordance with generally accepted accounting principles for governmental enterprises as prescribed from time to time by any regulatory body with jurisdiction over NCPA and by the Governmental Accounting Standards Board. If NCPA's audited financial statements are not available by the time the Annual Report is required to be filed pursuant to paragraph (a) of Section 3, the Annual Report shall contain unaudited financial statements in a format similar to the audited financial statements, and the audited financial statements shall be filed in the same manner as the Annual Report when they become available.

Any or all of the items listed above may be included by specific reference to other documents, including official statements of debt issues of NCPA or public entities related thereto, which have been submitted to the MSRB through the EMMA System or to the SEC. If the document included by reference is a final official statement, it must be available from the MSRB through the EMMA System. NCPA shall clearly identify each such other document so included by reference.

SECTION 5. Reporting of Significant Events.

(a) Pursuant to the provisions of this Section 5, upon the occurrence of any of the following events with respect to the 2022 Bonds, NCPA shall give, or cause to be given by so notifying the Dissemination Agent and instructing the Dissemination Agent to give, notice of occurrence of such event not later than ten (10) business days after the occurrence of the event, in each case, pursuant to paragraphs (b) and (c) of this Section 5, as applicable:

(1) principal and interest payment delinquencies;

(2) non-payment related defaults, if material;

(3) unscheduled draws on debt service reserves reflecting financial difficulties;

(4) unscheduled draws on credit enhancements reflecting financial difficulties;

(5) substitution of credit or liquidity providers, or their failure to perform;

(6) adverse tax opinions or the issuance by the Internal Revenue Service of a proposed or final determination of taxability or of a Notice of Proposed Issue (IRS Form 5701 TEB), or other material notices or determinations

by the Internal Revenue Service with respect to the tax status of the 2022 Bonds or other material events affecting the tax status of the 2022 Bonds;

(7) modifications to rights of the Holders of the 2022 Bonds, if material;

(8) optional, unscheduled or contingent 2022 Bond calls, if material, and tender offers;

(9) defeasances;

(10) release, substitution or sale of property securing repayment of the 2022 Bonds, if material;

(11) rating changes;

(12) bankruptcy, insolvency, receivership or similar event of NCPA or an obligated person (as defined in the Rule) with respect to the 2022 Bonds of which NCPA has actual knowledge;

(13) the consummation of a merger, consolidation, or acquisition involving NCPA or an obligated person (as defined in the Rule) with respect to the 2022 Bonds of which NCPA has actual knowledge or the sale of all or substantially all of the assets of NCPA or any such obligated person, other than in the ordinary course of business, the entry into a definitive agreement to undertake such an action or the termination of a definitive agreement relating to any such actions, other than pursuant to its terms, if material;

(14) appointment of a successor or additional trustee or the change of name of a trustee, if material;

(15) incurrence of a Financial Obligation of NCPA with respect to the Hydroelectric Project, if material, or agreement to covenants, events of default, remedies, priority rights, or other similar terms of a Financial Obligation of NCPA with respect to the Hydroelectric Project, any of which affect Holders of the 2022 Bonds, if material; or

(16) default, event of acceleration, termination event, modification of terms, or other similar events under the terms of a Financial Obligation of NCPA with respect to the Hydroelectric Project, any of which reflect financial difficulties.

For these purposes, (i) any event described in subparagraph (12) of this Section 5(a) is considered to occur when any of the following occur: the appointment of a receiver, fiscal agent or similar officer for an obligated person in a proceeding under the U.S. Bankruptcy Code or in any other proceeding under state or federal law in which a court or governmental authority has assumed jurisdiction over substantially all of the assets or business of the obligated person, or if such jurisdiction has been assumed by leaving the existing governmental body and officials or officers in possession but subject to the supervision and orders of a court or governmental authority, or the entry of an order confirming a plan of reorganization, arrangement or liquidation by a court or governmental authority having supervision or jurisdiction over substantially all of the assets or business of the obligated person; and (ii) NCPA intends to comply with the provisions hereof for the Listed Events described in subparagraphs (15) and (16) of this Section 5(a), and the definition of "Financial Obligation" in Section 2, with reference to the Rule, any other applicable federal securities laws and the guidance provided by the Commission in its Release No. 34-83885 dated August 20, 2018 (the "2018 Release"), and any further amendments or written guidance provided by the Commission or its staff with respect to the amendments to the Rule effected by the 2018 Release.

(b) Whenever NCPA obtains knowledge of the occurrence of a Listed Event described in paragraph (a) of this Section 5, NCPA shall either (i) promptly notify the Dissemination Agent in writing and instruct the Dissemination Agent to report the occurrence pursuant to Section 5(c) below or (ii) shall itself file a notice of such occurrence with the MSRB through the EMMA System.

(c) If the Dissemination Agent has been instructed by NCPA to report the occurrence of a Listed Event, the Dissemination Agent shall file a notice of such occurrence with the MSRB through the EMMA System.

(d) Any notice required by this Section 5 to be provided to the MSRB shall be provided in an electronic format and accompanied by identifying information as prescribed by the MSRB. Notwithstanding the foregoing provisions of this Section 5, notice of Listed Events described in subparagraphs (8) and (9) of Section 5(a) above need not be given under this Section 5(d) any earlier than the notice (if any) of the underlying event is given to Bondholders of affected 2022 Bonds pursuant to the Indenture.

SECTION 6. Termination of Reporting Obligation. The obligations of NCPA under this Disclosure Agreement shall terminate upon the legal defeasance, prior redemption or payment in full of all of the 2022 Bonds and with respect to any 2022 Bonds upon the maturity, defeasance, prior redemption or payment in full of such 2022 Bonds.

SECTION 7. Dissemination Agent. NCPA may, from time to time, appoint or engage a Dissemination Agent to assist it in carrying out its obligations under this Disclosure Agreement, and may discharge any such Dissemination Agent, with or without appointing a successor Dissemination Agent. The Dissemination Agent shall not be responsible in any manner for the content of any notice or report prepared by NCPA pursuant to this Disclosure Agreement. The initial Dissemination Agent shall be U.S. Bank Trust Company, National Association. NCPA shall be responsible for all fees and associated expenses of the Dissemination Agent.

SECTION 8. Amendment; Waiver. Notwithstanding any other provision of this Disclosure Agreement, NCPA and the Dissemination Agent may amend this Disclosure Agreement, and any provision of this Disclosure Agreement may be waived; provided that such amendment or waiver, in the opinion of nationally recognized bond counsel satisfactory to the Dissemination Agent, such amendment or waiver is permitted by the Rule.

In the event of any amendment or waiver of a provision of this Disclosure Agreement, NCPA shall describe such amendment in its next Annual Report, and shall include, as applicable, a narrative explanation of the reason for the amendment or waiver and its impact on the type (or in the case of a change of accounting principles, on the presentation) of financial information or operating data being presented by NCPA. In addition, if the amendment relates to the accounting principles to be followed in preparing financial statements, (i) notice of such change shall be given in the manner as provided under Section 5, and (ii) the Annual Report for the year in which the change is made should present a comparison (in narrative form and also, if feasible, in quantitative form) between the financial statements as prepared on the basis of the new accounting principles and those prepared on the basis of the former accounting principles.

SECTION 9. __Additional Information__. Nothing in this Disclosure Agreement shall be deemed to prevent NCPA from disseminating any other information, using the means of dissemination set forth in this Disclosure Agreement or any other means of communication, or including any other information in any Annual Report or notice of occurrence of a Listed Event, in addition to that which is required by this Disclosure Agreement. If NCPA chooses to include any information in any Annual Report or notice of occurrence of a Listed Event in addition to that which is specifically required by this Disclosure Agreement, NCPA shall have no obligation under this Agreement to update such information or include it in any future Annual Report or notice of occurrence of a Listed Event.

SECTION 10. __Default__. In the event of a failure of NCPA or the Dissemination Agent to comply with any provision of this Disclosure Agreement, the Trustee may (and, at the request of the Bondholders of at least 25% aggregate principal amount of Outstanding 2022 Bonds and the furnishing by such Bondholders of indemnity satisfactory to the Trustee against its costs and expenses, including, without limitation, fees and expenses of its attorneys, shall), or any Bondholder or Beneficial Owner of the 2022 Bonds may, take such actions as may be necessary and appropriate, including seeking mandate or specific performance by court order, to cause NCPA or the Dissemination Agent, as the case may be, to comply with its obligations under this Disclosure Agreement. A default under this Disclosure Agreement shall not be deemed an Event of Default under the Indenture, and the sole remedy under this Disclosure Agreement in the event of any failure of NCPA or the Dissemination Agent to comply with this Disclosure Agreement shall be an action to compel performance.

No Bondholder or Beneficial Owner may institute any such action, suit or proceeding to compel performance unless they shall have first filed with the Dissemination Agent and NCPA satisfactory written evidence of their status as such, and a written notice of and request to cure such failure, and NCPA shall have refused to comply therewith within a reasonable time. Any such action, suit or proceeding shall be brought in federal or state courts located in the County of Sacramento, California for the benefit of all Bondholders and Beneficial Owners of the 2022 Bonds.

SECTION 11. __Duties, Immunities and Liabilities of Dissemination Agent__. The Dissemination Agent shall have only such duties as are specifically set forth in this Agreement, and no further duties or responsibilities shall be implied, and the Dissemination Agent's obligation to deliver the information at the times and with the contents described herein shall be limited to the extent NCPA has provided such information to the Dissemination Agent as required by this Agreement. The Dissemination Agent shall not have any liability under, nor duty to inquire into the terms and provisions of, any agreement or instructions, other than as outlined in this Agreement. The Dissemination Agent may rely and shall be protected in acting or refraining from acting upon any written notice, instruction or request furnished to it hereunder and believed by it to be genuine and to have been signed or presented by the proper party or parties. The Dissemination Agent shall be under no duty to inquire into or investigate the validity, accuracy or content of any such document. The Dissemination Agent shall not be liable for any action taken or omitted by it in good faith unless a court of competent jurisdiction determines that the Dissemination Agent's negligence or willful misconduct was the primary cause of any loss to NCPA. The Dissemination Agent shall not incur any liability for following the instructions herein contained or expressly provided for, or written instructions given by NCPA. In the administration of this Agreement, the Dissemination Agent may execute any of its powers and perform its duties hereunder directly or through agents or attorneys and may consult with counsel, accountants and other skilled persons to be selected and retained by it. The Dissemination Agent shall not be liable for anything done, suffered or omitted in good faith by it in accordance with the advice or opinion of any such counsel, accountants or other skilled persons. The Dissemination Agent may resign and be discharged from its duties or obligations hereunder by giving notice in writing of such resignation specifying a date when such resignation shall take effect. Any corporation or association into which the Dissemination Agent in its individual capacity may be merged or converted or with which it may be consolidated, or any corporation or association resulting from any merger, conversion or consolidation to which the Dissemination Agent in its individual capacity shall be a party, or any corporation or association to which all or substantially all the corporate trust business of the Dissemination Agent in its individual capacity may be sold or otherwise transferred, shall be the Dissemination Agent under this Agreement without further act. NCPA covenants and agrees to hold the Dissemination Agent and its directors, officers, agents and employees (collectively, the "Indemnitees") harmless from and against any and all liabilities, losses, damages, fines, suits, actions, demands, penalties, costs and expenses, including out-of-pocket, incidental expenses, legal fees and expenses, the allocated costs and expenses of in-house counsel and legal staff and the costs and expenses of defending or preparing to defend against any claim ("Losses") that may be imposed on, incurred by, or asserted against, the Indemnitees or any of them for following any instruction or other direction upon which the Dissemination Agent is authorized to rely pursuant to the terms of this Agreement. In addition to and not in limitation of the immediately preceding sentence, NCPA also covenants and agrees to indemnify and hold the Indemnitees and each of them harmless from and against any and all Losses that may be imposed on, incurred by, or asserted against the Indemnitees or any of them in connection with or arising out of the Dissemination Agent's performance under this Agreement provided the Dissemination Agent has not acted with negligence or engaged in willful misconduct. Anything in this Agreement to the contrary notwithstanding, in no event shall the Dissemination Agent be liable for special, indirect or consequential loss or damage of any kind whatsoever (including but not limited to lost profits), even if the Dissemination Agent has been advised of such loss or damage and regardless of the form of action. The obligations of NCPA under this Section shall survive resignation or removal of the Dissemination Agent and payment of the 2022 Bonds. The Dissemination Agent shall have no obligation to disclose information about the 2022 Bonds except as expressly provided herein. The fact that the Dissemination Agent or any affiliate thereof may have any fiduciary or banking relationship with NCPA, apart from the relationship created by the Rule, shall not be construed to mean that the Dissemination Agent has actual knowledge of any event or condition except as may be provided by written notice from NCPA. Nothing in this Agreement shall be construed to require the Dissemination Agent to interpret or provide an opinion concerning any information made public. If the Dissemination Agent receives a request for an interpretation or opinion, the Dissemination Agent may refer such request to NCPA for response. NCPA shall pay or reimburse the Dissemination Agent for its fees and expenses for the Dissemination Agent's services rendered in accordance with this Agreement. The Dissemination Agent shall have no duty or obligation to review any information provided to it hereunder and shall not be deemed to be acting in any fiduciary capacity for NCPA, the Bondholder or any other party.

SECTION 12. Beneficiaries. This Disclosure Agreement shall inure solely to the benefit of NCPA, the Trustee, the Dissemination Agent, the Participating Underwriters and the Bondholders and Beneficial Owners from time to time of the 2022 Bonds, and shall create no rights in any other person or entity.

SECTION 13. California Law. This Disclosure Agreement shall be construed and governed in accordance with the laws of the State of California.

SECTION 14. Notices. All written notices to be given hereunder shall be given in person or by mail to the party entitled thereto at its address set forth below, or at such other address as such party may provide to the other parties in writing from time to time, namely:

To NCPA:	Northern California Power Agency 651 Commerce Drive Roseville, California 95678 Attention: General Manager Telephone: (916) 781-3636 Fax: (916) 783-7693
To the Dissemination Agent:	U.S. Bank Trust Company, National Association 100 Wall Street, Suite 1600 New York, New York 10005 Attention: Corporate Trust Department Telephone: (212) 361-4385 Fax: (212) 514-6841

NCPA and the Dissemination Agent may, by notice given hereunder, designate any further or different addresses to which subsequent notices, certificates or other communications shall be sent.

SECTION 15. Counterparts. This Disclosure Agreement may be executed in several counterparts, each of which shall be an original and all of which shall constitute but one and the same instrument.

IN WITNESS WHEREOF, the undersigned have executed the Disclosure Agreement to be executed as of the date set forth above.

NORTHERN CALIFORNIA POWER AGENCY

By:____________________________________
Its:

U.S. BANK TRUST COMPANY, NATIONAL ASSOCIATION, as Dissemination Agent

By:____________________________________
Authorized Signatory

EXHIBIT A

NOTICE TO REPOSITORIES OF FAILURE TO FILE ANNUAL REPORT

Name of Issuer:	Northern California Power Agency ("NCPA")
Name of Bond Issue:	$__________ aggregate principal amount of Northern California Power Agency Hydroelectric Project Number One Revenue Bonds, 2022 Refunding Series A (the "2022A Bonds") and $__________ aggregate principal amount of Northern California Power Agency Hydroelectric Project Number One Revenue Bonds, 2022 Taxable Refunding Series B (the "2022B Bonds" and together with the 2022A Bonds, the "2022 Bonds")
Date of Issuance:	April ___, 2022

NOTICE IS HEREBY GIVEN that NCPA has not provided an Annual Report with respect to the 2022 Bonds as required by Section 3 of the Continuing Disclosure Agreement with respect to the 2022 Bonds, dated April ____, 2022, by and between NCPA and U.S. Bank Trust Company, National Association, as Dissemination Agent. [NCPA anticipates that the Annual Report will be filed by __________.]

Dated: ____________________

U. S. BANK TRUST COMPANY, NATIONAL ASSOCIATION, as Dissemination Agent on behalf of the Northern California Power Agency

cc: NCPA

CONTINUING DISCLOSURE AGREEMENT
BY AND BETWEEN THE
[SIGNIFICANT SHARE PROJECT PARTICIPANT]
AND
U.S. BANK TRUST COMPANY, NATIONAL ASSOCIATION

This Continuing Disclosure Agreement (the "Disclosure Agreement"), dated April ___, 2022, is executed and delivered by the [Significant Share Project Participant] (the "Project Participant") and U.S. Bank Trust Company, National Association, as Dissemination Agent (the "Dissemination Agent") in connection with the issuance by Northern California Power Agency ("NCPA") of $__________ aggregate principal amount of Northern California Power Agency Hydroelectric Project Number One Revenue Bonds, 2022 Refunding Series A (the "2022A Bonds") and 2022 Taxable Refunding Series B Bonds (the "2022B Bonds" and together with the 2022A Bonds, the "2022 Bonds"). The 2022 Bonds were issued pursuant to an Indenture of Trust, dated as of March 1, 1985, as amended and supplemented, including as supplemented by the Twenty-Seventh Supplemental Indenture of Trust, dated as of April 1, 2022 , with respect to the 2022A Bonds, and by the Twenty-Eighth Supplemental Indenture of Trust, dated as of April 1, 2022, with respect to the 2022B Bonds (collectively, the "Indenture"), each by and between NCPA and U.S. Bank Trust Company, National Association, as the Trustee. The Project Participant and the Dissemination Agent covenant and agree as follows:

SECTION 1. <u>Purpose of the Disclosure Agreement</u>. This Disclosure Agreement is being executed and delivered by the Project Participant and the Dissemination Agent for the benefit of the Bondholders and Beneficial Owners of the 2022 Bonds and in order to assist the Participating Underwriters in complying with the Rule.

SECTION 2. <u>Definitions</u>. In addition to the definitions set forth in the Indenture, which apply to any capitalized term used in this Disclosure Agreement unless otherwise defined in this Section 2, the following capitalized terms shall have the following meanings:

"Annual Report" shall mean any Annual Report with respect to the 2022 Bonds provided by the Project Participant pursuant to, and as described in, Sections 3 and 4 of this Disclosure Agreement.

"Beneficial Owner" shall mean any person who has or shares the power, directly or indirectly, to make investment decisions regarding ownership of any 2022 Bonds (including without limitation persons holding 2022 Bonds through nominees, depositories or other intermediaries).

"Disclosure Representative" shall mean any of the City Manager or the Director of Finance of the Project Participant, or his or her designee, or such other officer or employee as the Project Participant shall designate in writing to NCPA and the Trustee from time to time.

"Dissemination Agent" shall mean U.S. Bank Trust Company, National Association, acting solely in its capacity as Dissemination Agent hereunder, or any successor Dissemination Agent designated in writing by the Project Participant and which has filed with NCPA and the Trustee a written acceptance of such designation.

"EMMA System" shall mean the MSRB's Electronic Municipal Market Access System or such other electronic system designated by the MSRB.

"Financial Obligation" shall mean a (a) debt obligation; (b) derivative instrument entered into in connection with, or pledged as security or a source of payment for, an existing or planned debt obligation;

or (c) guarantee of a debt obligation or any such derivative instrument in each case, which “financial obligation” is payable from revenues of the Project Participant’s electric system; provided that “financial obligation” shall not include municipal securities as to which a final official statement (as defined in the Rule) has been provided to the MSRB consistent with the Rule.

“Listed Event” shall mean any of the events listed in Section 5(a) of this Disclosure Agreement.

“MSRB” shall mean the Municipal Securities Rulemaking Board, or any successor thereto.

“Participating Underwriters” shall mean the original underwriters of the 2022 Bonds required to comply with the Rule in connection with the offering of the 2022 Bonds.

“Rule” shall mean Rule 15c2-12(b)(5) adopted by the SEC under the Securities Exchange Act of 1934, as the same may be amended from time to time.

“SEC” shall mean the United States Securities and Exchange Commission.

SECTION 3. Provision of Annual Reports.

(a) With respect to the 2022 Bonds, the Project Participant shall, or shall cause the Dissemination Agent to, not later than 210 days after the end of each fiscal year of the Project Participant (which presently ends on June 30), commencing with the report for the Fiscal Year ending June 30, 2022, provide to the MSRB through the EMMA System, in an electronic format and accompanied by identifying information all as prescribed by the MSRB, an Annual Report which is consistent with the requirements of Section 4 of this Disclosure Agreement. The Annual Report may be submitted as a single document or as separate documents comprising a package, and may include by reference other information as provided in Section 4 of this Disclosure Agreement; provided, that the audited financial statements of the Project Participant may be submitted separately from the balance of the Annual Report and later than the date required above for the filing of the Annual Report if they are not available by that date. If the fiscal year changes for the Project Participant, the Project Participant shall give notice of such change prior to the next date by which the Project Participant otherwise would be required to provide its Annual Report pursuant to this Section and in the manner provided for giving notices under Section 5 hereof.

(b) Not later than fifteen (15) business days prior to the date specified in paragraph (a) of this Section 3 for providing the Annual Report to the MSRB, the Project Participant shall provide its Annual Report to the Dissemination Agent. If by such date, the Dissemination Agent has not received a copy of the Annual Report from the Project Participant, the Dissemination Agent shall contact the Project Participant to determine if the Project Participant is in compliance with paragraph (a) of this Section 3.

(c) If the Dissemination Agent is unable to verify that an Annual Report has been provided to the MSRB by the date required in paragraph (a) of this Section 3, the Dissemination Agent shall send a notice to the MSRB through the EMMA System in substantially the form attached hereto as Exhibit A.

(d) Upon the provision by the Dissemination Agent of any Annual Report to the MSRB pursuant to paragraph (a) of this Section 3, the Dissemination Agent shall deliver a confirmation in writing to the Project Participant certifying that the Annual Report has been provided to the MSRB pursuant to this Disclosure Agreement and stating the date it was provided.

SECTION 4. Content of Annual Reports. The Project Participant's Annual Report shall contain or include by reference the following:

(i) A summary of the operating results and selected balance sheet information for the Project Participant's electric system for the most recently completed fiscal year;

(ii) A summary of power supply resources of the Project Participant's electric system in tabular form for the most recently completed fiscal year;

(iii) A summary of customers, energy sales, revenues and peak demand of the Project Participant's electric system in tabular form for the most recently completed fiscal year; and

(iv) The audited financial statements of the Project Participant's electric utility fund for the most recently completed fiscal year, prepared in accordance with generally accepted accounting principles for governmental enterprises as prescribed from time to time by any regulatory body with jurisdiction over the Project Participant and by the Governmental Accounting Standards Board. If the Project Participant's electric utility fund audited financial statements are not available by the time the Annual Report is required to be filed pursuant to Section 3(a), the Annual Report shall contain unaudited financial statements in a format similar to the audited financial statements, and the audited financial statements shall be filed in the same manner as the Annual Report when they become available.

Any or all of the items listed above may be included by specific reference to other documents, including official statements of debt issues of the Project Participant or public entities related thereto, which have been submitted to the MSRB through the EMMA System or to the SEC. If the document included by reference is a final official statement, it must be available from the MSRB through the EMMA System. The Project Participant shall clearly identify each such other document so included by reference.

SECTION 5. Reporting of Significant Events.

(a) Pursuant to the provisions of this Section 5, upon the occurrence of any of the following events with respect to the Project Participant, the Project Participant shall give, or cause to be given by so notifying the Dissemination Agent and instructing the Dissemination Agent to give, notice of occurrence of such event not later than ten (10) business days after the occurrence of the event, in each case, pursuant to paragraphs (b) and (c) of this Section 5, as applicable:

(1) bankruptcy, insolvency, receivership or similar event of the Project Participant;

(2) the consummation of a merger, consolidation, or acquisition involving the Project Participant or the sale of all or substantially all of the electric system assets of the Project Participant, other than in the ordinary course of business, the entry into a definitive agreement to undertake such an action or the termination of a definitive agreement relating to any such actions, other than pursuant to its terms, if material;

(3) incurrence of a Financial Obligation of the Project Participant payable from revenues of the Project Participant's electric system, if material, or agreement to covenants, events of default, remedies, priority rights, or other similar terms of a Financial Obligation of the Project Participant

payable from revenues of the Project Participant's electric system, any of which affect Holders of the 2022 Bonds, if material; or

(4) default, event of acceleration, termination event, modification of terms, or other similar events under the terms of a Financial Obligation of the Project Participant payable from revenues of the Project Participant's electric system, any of which reflect financial difficulties.

For these purposes, (i) any event described in subparagraph (1) of this Section 5(a) is considered to occur when any of the following occur: the appointment of a receiver, fiscal agent, or similar officer for the Project Participant in a proceeding under the United States Bankruptcy Code or in any other proceeding under state or federal law in which a court or governmental authority has assumed jurisdiction over substantially all of the assets or business of the Project Participant or its electric system, or if such jurisdiction has been assumed by leaving the existing governing body and officials or officers in possession but subject to the supervision and orders of a court or governmental authority, or the entry of an order confirming a plan of reorganization, arrangement, or liquidation by a court or governmental authority having supervision or jurisdiction over substantially all of the assets or business of the Project Participant or its electric system; and (ii) the Project Participant intends to comply with the provisions hereof for the Listed Events described in subparagraphs (3) and (4) of this Section 5(a), and the definition of "Financial Obligation" in Section 2, with reference to the Rule, any other applicable federal securities laws and the guidance provided by the Commission in its Release No. 34-83885 dated August 20, 2018 (the "2018 Release"), and any further amendments or written guidance provided by the Commission or its staff with respect to the amendments to the Rule effected by the 2018 Release.

(b) Whenever the Project Participant obtains knowledge of the occurrence of a Listed Event described in paragraph (a) of this Section 5, the Project Participant shall either (i) promptly notify the Dissemination Agent in writing and instruct the Dissemination Agent to report the occurrence pursuant to Section 5(c) below or (ii) shall itself file a notice of such occurrence with the MSRB through the EMMA System.

(c) If the Dissemination Agent has been instructed by the Project Participant to report the occurrence of a Listed Event, the Dissemination Agent shall file a notice of such occurrence with the MSRB through the EMMA System.

(d) Any notice required by this Section 5 to be provided to the MSRB shall be provided in an electronic format and accompanied by identifying information as prescribed by the MSRB.

SECTION 6. Termination of Reporting Obligation. The obligations of the Project Participant under this Disclosure Agreement shall terminate upon the legal defeasance, prior redemption or payment in full of all of the 2022 Bonds and with respect to any 2022 Bonds upon the maturity, defeasance, prior redemption or payment in full of such 2022 Bonds.

SECTION 7. Dissemination Agent. The Project Participant may, from time to time, appoint or engage a Dissemination Agent to assist it in carrying out its obligations under this Disclosure Agreement, and may discharge any such Dissemination Agent, with or without appointing a successor Dissemination Agent. The Dissemination Agent shall not be responsible in any manner for the content of any notice or report prepared by the Project Participant pursuant to this Disclosure Agreement. The initial Dissemination Agent shall be U.S. Bank Trust Company, National Association. The Project Participant shall be responsible for all fees and associated expenses of the Dissemination Agent.

SECTION 8. Amendment; Waiver. Notwithstanding any other provision of this Disclosure Agreement, the Project Participant and the Dissemination Agent may amend this Disclosure Agreement, and any provision of this Disclosure Agreement may be waived; provided that such amendment or waiver, in the opinion of nationally recognized bond counsel satisfactory to the Dissemination Agent, such amendment or waiver is permitted by the Rule.

In the event of any amendment or waiver of a provision of this Disclosure Agreement, the Project Participant shall describe such amendment in its next Annual Report, and shall include, as applicable, a narrative explanation of the reason for the amendment or waiver and its impact on the type (or in the case of a change of accounting principles, on the presentation) of financial information or operating data being presented by the Project Participant. In addition, if the amendment relates to the accounting principles to be followed in preparing financial statements, (i) notice of such change shall be given in the manner as provided under Section 5, and (ii) the Annual Report for the year in which the change is made should present a comparison (in narrative form and also, if feasible, in quantitative form) between the financial statements as prepared on the basis of the new accounting principles and those prepared on the basis of the former accounting principles.

SECTION 9. Additional Information. Nothing in this Disclosure Agreement shall be deemed to prevent the Project Participant from disseminating any other information, using the means of dissemination set forth in this Disclosure Agreement or any other means of communication, or including any other information in any Annual Report or notice of occurrence of a Listed Event, in addition to that which is required by this Disclosure Agreement. If the Project Participant chooses to include any information in any Annual Report or notice of occurrence of a Listed Event in addition to that which is specifically required by this Disclosure Agreement, the Project Participant shall have no obligation under this Agreement to update such information or include it in any future Annual Report or notice of occurrence of a Listed Event.

SECTION 10. Default. In the event of a failure of the Project Participant or the Dissemination Agent to comply with any provision of this Disclosure Agreement, the Trustee may (and, at the request of the Bondholders of at least 25% aggregate principal amount of Outstanding 2022 Bonds and the furnishing by such Bondholders of indemnity satisfactory to the Trustee against its costs and expenses, including, without limitation, fees and expenses of its attorneys, shall), or any Bondholder or Beneficial Owner of the 2022 Bonds may, take such actions as may be necessary and appropriate, including seeking mandate or specific performance by court order, to cause the Project Participant or the Dissemination Agent, as the case may be, to comply with its obligations under this Disclosure Agreement. A default under this Disclosure Agreement shall not be deemed an Event of Default under the Indenture, and the sole remedy under this Disclosure Agreement in the event of any failure of the Project Participant or the Dissemination Agent to comply with this Disclosure Agreement shall be an action to compel performance.

No Bondholder or Beneficial Owner may institute any such action, suit or proceeding to compel performance unless they shall have first filed with the Dissemination Agent and the Project Participant satisfactory written evidence of their status as such, and a written notice of and request to cure such failure, and the Project Participant shall have refused to comply therewith within a reasonable time. Any such action, suit or proceeding shall be brought in federal or state courts located in the County of Sacramento, California for the benefit of all Bondholders and Beneficial Owners of the 2022 Bonds.

SECTION 11. Duties, Immunities and Liabilities of Dissemination Agent. The Dissemination Agent shall have only such duties as are specifically set forth in this Agreement, and no further duties or responsibilities shall be implied, and the Dissemination Agent's obligation to deliver the information at the times and with the contents described herein shall be limited to the extent the Project Participant has provided such information to the Dissemination Agent as required by this Agreement. The

Dissemination Agent shall not have any liability under, nor duty to inquire into the terms and provisions of, any agreement or instructions, other than as outlined in this Agreement. The Dissemination Agent may rely and shall be protected in acting or refraining from acting upon any written notice, instruction or request furnished to it hereunder and believed by it to be genuine and to have been signed or presented by the proper party or parties. The Dissemination Agent shall be under no duty to inquire into or investigate the validity, accuracy or content of any such document. The Dissemination Agent shall not be liable for any action taken or omitted by it in good faith unless a court of competent jurisdiction determines that the Dissemination Agent's negligence or willful misconduct was the primary cause of any loss to the Project Participant. The Dissemination Agent shall not incur any liability for following the instructions herein contained or expressly provided for, or written instructions given by the Project Participant. In the administration of this Agreement, the Dissemination Agent may execute any of its powers and perform its duties hereunder directly or through agents or attorneys and may consult with counsel, accountants and other skilled persons to be selected and retained by it. The Dissemination Agent shall not be liable for anything done, suffered or omitted in good faith by it in accordance with the advice or opinion of any such counsel, accountants or other skilled persons. The Dissemination Agent may resign and be discharged from its duties or obligations hereunder by giving notice in writing of such resignation specifying a date when such resignation shall take effect. Any corporation or association into which the Dissemination Agent in its individual capacity may be merged or converted or with which it may be consolidated, or any corporation or association resulting from any merger, conversion or consolidation to which the Dissemination Agent in its individual capacity shall be a party, or any corporation or association to which all or substantially all the corporate trust business of the Dissemination Agent in its individual capacity may be sold or otherwise transferred, shall be the Dissemination Agent under this Agreement without further act. The Project Participant covenants and agrees to hold the Dissemination Agent and its directors, officers, agents and employees (collectively, the "Indemnitees") harmless from and against any and all liabilities, losses, damages, fines, suits, actions, demands, penalties, costs and expenses, including out-of-pocket, incidental expenses, legal fees and expenses, the allocated costs and expenses of in-house counsel and legal staff and the costs and expenses of defending or preparing to defend against any claim ("Losses") that may be imposed on, incurred by, or asserted against, the Indemnitees or any of them for following any instruction or other direction upon which the Dissemination Agent is authorized to rely pursuant to the terms of this Agreement. In addition to and not in limitation of the immediately preceding sentence, the Project Participant also covenants and agrees to indemnify and hold the Indemnitees and each of them harmless from and against any and all Losses that may be imposed on, incurred by, or asserted against the Indemnitees or any of them in connection with or arising out of the Dissemination Agent's performance under this Agreement provided the Dissemination Agent has not acted with negligence or engaged in willful misconduct. Anything in this Agreement to the contrary notwithstanding, in no event shall the Dissemination Agent be liable for special, indirect or consequential loss or damage of any kind whatsoever (including but not limited to lost profits), even if the Dissemination Agent has been advised of such loss or damage and regardless of the form of action. The obligations of the Project Participant under this Section shall survive resignation or removal of the Dissemination Agent and payment of the 2022 Bonds. The Dissemination Agent shall have no obligation to disclose information about the 2022 Bonds except as expressly provided herein. The fact that the Dissemination Agent or any affiliate thereof may have any fiduciary or banking relationship with the Project Participant, apart from the relationship created by the Rule, shall not be construed to mean that the Dissemination Agent has actual knowledge of any event or condition except as may be provided by written notice from the Project Participant. Nothing in this Agreement shall be construed to require the Dissemination Agent to interpret or provide an opinion concerning any information made public. If the Dissemination Agent receives a request for an interpretation or opinion, the Dissemination Agent may refer such request to the Project Participant for response. The Project Participant shall pay or reimburse the Dissemination Agent for its fees and expenses for the Dissemination Agent's services rendered in accordance with this Agreement. The Dissemination Agent shall have no duty or obligation to review any information provided to it hereunder and shall not be deemed to be acting in any fiduciary capacity for the Project Participant, the Bondholder or any other party.

SECTION 12. Beneficiaries. This Disclosure Agreement shall inure solely to the benefit of the Project Participant, the Trustee, the Dissemination Agent, the Participating Underwriters and the Bondholders and Beneficial Owners from time to time of the 2022 Bonds, and shall create no rights in any other person or entity.

SECTION 13. California Law. This Disclosure Agreement shall be construed and governed in accordance with the laws of the State of California.

SECTION 14. Notices. All written notices to be given hereunder shall be given in person or by mail to the party entitled thereto at its address set forth below, or at such other address as such party may provide to the other parties in writing from time to time, namely:

To the Project Participant: [Significant Share Project Participant]
____
____
____
____
____

To the Dissemination Agent: U.S. Bank Trust Company, National Association
100 Wall Street, Suite 1600
New York, New York 10005
Attention: Corporate Trust Department
Telephone: (212) 361-4385
Fax: (212) 514-6841

The Project Participant and the Dissemination Agent may, by notice given hereunder, designate any further or different addresses to which subsequent notices, certificates or other communications shall be sent.

SECTION 15. Counterparts. This Disclosure Agreement may be executed in several counterparts, each of which shall be an original and all of which shall constitute but one and the same instrument.

IN WITNESS WHEREOF, the undersigned have executed the Disclosure Agreement to be executed as of the date set forth above.

[SIGNIFICANT SHARE PROJECT PARTICIPANT]

By:________________________________
Name:______________________________
Title:_______________________________

U.S. BANK TRUST COMPANY, NATIONAL ASSOCIATION, as Dissemination Agent

By:________________________________
Authorized Signatory

EXHIBIT A

NOTICE TO REPOSITORIES OF FAILURE TO FILE ANNUAL REPORT

Name of Issuer:	Northern California Power Agency ("NCPA")
Name of Bond Issue:	$__________ aggregate principal amount of Northern California Power Agency Hydroelectric Project Number One Revenue Bonds, 2022 Refunding Series A (the "2022A Bonds") and $__________ aggregate principal amount of Northern California Power Agency Hydroelectric Project Number One Revenue Bonds, 2022 Taxable Refunding Series B (the "2022B Bonds" and together with the 2022A Bonds, the "2022 Bonds")
Name of Obligated Party:	[Significant Share Project Participant] (the "Project Participant")
Date of Issuance:	April ___, 2022

NOTICE IS HEREBY GIVEN that the Project Participant has not provided an Annual Report with respect to the 2022 Bonds as required by Section 3 of the Continuing Disclosure Agreement with respect to the 2022 Bonds, dated April ___, 2022, by and between the Project Participant and U.S. Bank Trust Company, National Association, as Dissemination Agent. [The Project Participant anticipates that the Annual Report will be filed by __________.]

Dated: ____________________

U.S. BANK TRUST COMPANY, NATIONAL
ASSOCIATION, as Dissemination Agent
on behalf of the Northern California Power Agency

cc: Project Participant

APPENDIX F

PROPOSED FORMS OF BOND COUNSEL OPINION AND SPECIAL TAX COUNSEL OPINION

PROPOSED FORM OF BOND COUNSEL OPINION

Upon the delivery of the 2022 Bonds, Stradling Yocca Carlson & Rauth, a Professional Corporation, Newport Beach, California, proposes to render its final approving opinion with respect to the 2022 Bonds in substantially the following form:

[Closing Date]

Commission
Northern California Power Agency
Roseville, California

Northern California Power Agency
Hydroelectric Project Number One Revenue Bonds

$________	$_________
2022 Refunding Series A	2022 Taxable Refunding Series B

Ladies and Gentlemen:

We have acted as bond counsel to the Northern California Power Agency (the "Agency") in connection with the issuance of $_________ aggregate principal amount of its Hydroelectric Project Number One Revenue Bonds, 2022 Refunding Series A (the "2022 Series A Bonds") and $_________ aggregate principal amount of its Hydroelectric Project Number One Revenue Bonds, 2022 Taxable Series B (the "2022 Series B Bonds" and, together with the 2022 Series A Bonds, the "2022 Bonds"). The 2022 Bonds are being issued pursuant to the provisions of Article 4 of Chapter 5 of Division 7 of Title 1, and Articles 10 and 11 of Chapter 3 of Part 1 of Division 2 of Title 5, of the Government Code of the State of California (collectively, the "Bond Law"), and the Indenture of Trust, dated as of March 1, 1985, by and between the Agency and U.S. Bank Trust Company, National Association, as successor trustee (the "Trustee"), as amended and supplemented, including as supplemented by the Twenty-Seventh Supplemental Indenture of Trust, dated as of [April 1], 2022, providing for the issuance of the 2022 Series A Bonds, and the Twenty-Eighth Supplemental Indenture of Trust, dated as of [April 1], 2022, providing for the issuance of the 2022 Series B Bonds (collectively, the "Indenture"). Capitalized terms not otherwise defined herein shall have the meanings ascribed thereto in the Indenture.

The 2022 Bonds are being issued to provide the funds necessary to refund the Agency's outstanding Hydroelectric Project Number One Revenue Bonds, 2010 Series A and related purposes.

In our capacity as bond counsel, we have reviewed the Bond Law, the Indenture, the Hydroelectric Project Member Agreement, certifications of the Agency, the Trustee, the Project Participants and others, opinions of counsel to the Agency, the Trustee and to each Project Participant, and such other documents, opinions and instruments as we deemed necessary to render the opinions set forth herein.

We have assumed the genuineness of all documents and signatures presented to us (whether as originals or as copies) and the due and legal execution and delivery thereof by, and validity against, any parties other than the Agency, and, with respect to the Hydroelectric Project Member Agreement, the Project Participants. We have not undertaken to verify independently, and have assumed, the accuracy of the factual matters represented, warranted or certified in the documents, and of the legal conclusions contained in the opinions referred to in the third paragraph hereof. Furthermore, we have assumed compliance with all covenants and agreements contained in the Indenture and the Hydroelectric Project Member Agreement. In addition, we call attention to the fact that the rights and obligations under the 2022 Bonds, the Indenture and the Hydroelectric Project Member Agreement, and the enforceability thereof, may be subject to bankruptcy, insolvency, receivership, reorganization, debt adjustment, fraudulent conveyance, moratorium, and other similar laws affecting creditors' rights generally, to the application of general principles of equity, including, without limitation, concepts of materiality, reasonableness, good faith and fair dealing, to the possible unavailability of specific performance or injunctive relief, regardless of whether considered in a proceeding in equity or at law, and to the limitations on legal remedies against governmental entities in California (including, but not limited to, rights of indemnification).

Based on and subject to the foregoing, and in reliance thereon, as of the date hereof, we are of the following opinions:

1. The 2022 Bonds constitute the valid and binding special, limited obligations of the Agency payable solely from, and secured solely by, the Trust Estate.

2. The Indenture has been duly executed and delivered by, and constitutes the valid and binding obligation of, the Agency. The Indenture creates a valid pledge of the Trust Estate to secure the payment of the principal and redemption price of, and the interest on, the Bonds, including the 2022 Bonds, to the extent set forth in the Indenture, subject to the provisions of the Indenture permitting the application thereof for the purposes and on the terms and conditions set forth therein.

3. The 2022 Bonds are payable solely from the funds provided in the Indenture and shall not constitute a charge against the general credit of the Agency. The 2022 Bonds are not secured by a legal or equitable pledge of, or charge or lien upon, any property of the Agency or any of its income or receipts except the Trust Estate. Neither the faith and credit nor the taxing power of the State of California or of any political subdivision thereof, any member of the Agency or any Project Participant is pledged to the payment of the principal or redemption price of, or interest on, the 2022 Bonds. The 2022 Bonds are not a debt of the State of California, and said State or any public agency thereof (other than the Agency), any member of the Agency or any Project Participant is not liable for the payment thereof.

4. The Hydroelectric Project Member Agreement has been duly executed and delivered by the Agency and the Project Participants and constitutes a valid and binding agreement of the parties thereto.

We express no opinion as to any federal, state or local tax consequences of the ownership or disposition of the 2022 Bonds or the receipt of interest thereon.

Our opinions are based on existing law, which is subject to change. Such opinions are further based on our knowledge of facts as of the date hereof. We assume no duty to update or supplement our opinions to reflect any facts or circumstances that may hereafter come to our attention or to reflect any changes in any law that may hereafter occur or become effective. Moreover, our opinions are not a guarantee of result and represent our legal judgment based upon our review of existing law that we deem relevant to such opinions and in reliance upon the representations and covenants referenced above.

No opinion is expressed herein on the accuracy, completeness or sufficiency of the Official Statement or other offering material relating to the 2022 Bonds.

Respectfully submitted,

PROPOSED FORM OF OPINION OF SPECIAL TAX COUNSEL

Upon the delivery of the 2022 Bonds, Nixon Peabody LLP, Special Tax Counsel to NCPA, proposes to render its tax opinion with respect to the 2022 Bonds in substantially the following form:

[Closing Date]

Commission
Northern California Power Agency
Roseville, California

Northern California Power Agency
Hydroelectric Project Number One Revenue Bonds

$________	$_________
2022 Refunding Series A	2022 Taxable Refunding Series B

Ladies and Gentlemen:

We have acted as special tax counsel to the Northern California Power Agency (the "Agency") in connection with the issuance of $_________ aggregate principal amount of its Hydroelectric Project Number One Revenue Bonds, 2022 Refunding Series A (the "2022 Series A Bonds") and $_________ aggregate principal amount of its Hydroelectric Project Number One Revenue Bonds, 2022 Taxable Series B (the "2022 Series B Bonds" and, together with the 2022 Series A Bonds, the "2022 Bonds"). The 2022 Bonds are being issued pursuant to the provisions of Article 4 of Chapter 5 of Division 7 of Title 1, and Articles 10 and 11 of Chapter 3 of Part 1 of Division 2 of Title 5, of the Government Code of the State of California (collectively, the "Bond Law"), and the Indenture of Trust, dated as of March 1, 1985, by and between the Agency and U.S. Bank Trust Company, National Association, as successor trustee (the "Trustee"), as amended and supplemented, including as supplemented by the Twenty-Seventh Supplemental Indenture of Trust, dated as of [April 1], 2022, providing for the issuance of the 2022 Series A Bonds, and the Twenty-Eighth Supplemental Indenture of Trust, dated as of [April 1], 2022, providing for the issuance of the 2022 Series B Bonds (collectively, the "Indenture"). Capitalized terms not otherwise defined herein shall have the meanings ascribed thereto in the Indenture. In rendering the opinions set forth below, we have relied upon the approving opinions of Stradling Yocca Carlson & Rauth, a Professional Corporation, Bond Counsel to the Agency, delivered on even date herewith, relating among other things to the validity of the 2022 Bonds.

The 2022 Bonds are being issued to provide the funds necessary to refund the Agency's outstanding Hydroelectric Project Number One Revenue Bonds, 2010 Series A and related purposes.

In our capacity as special tax counsel, we have reviewed the Bond Law, the Indenture, the Hydroelectric Project Member Agreement, the Agency's Tax Certificate as to Arbitrage and the Provisions of Sections 103 and 141-150 of the Internal Revenue Code of 1986 with respect to the 2022 Series A Bonds (the "Tax Certificate"), certifications of the Agency, the Trustee, the Project Participants and others, opinions of counsel to the Agency, the Trustee and to each Project Participant, and such other documents, opinions and instruments as we deemed necessary to render the opinions set forth herein.

We have assumed the genuineness of all documents and signatures presented to us (whether as originals or as copies) and the due and legal execution and delivery thereof by, and validity against, any parties other than the Agency, and, with respect to the Hydroelectric Project Member Agreement, the Project Participants. We have not undertaken to verify independently, and have assumed, the accuracy of the factual matters represented, warranted or certified in the documents, and of the legal conclusions contained in the opinions referred to in the third paragraph hereof. Furthermore, we have assumed compliance with all covenants and agreements contained in the Indenture and the Hydroelectric Project Member Agreement. Based on and subject to the foregoing, and in reliance thereon, as of the date hereof, we are of the following opinions:

The Internal Revenue Code of 1986 (the "Code") sets forth certain requirements which must be met subsequent to the issuance and delivery of the 2022 Series A Bonds for interest thereon to be and remain excluded from gross income for federal income tax purposes. Noncompliance with such requirements could cause the interest on the 2022 Series A Bonds to be included in gross income for federal income tax purposes retroactive to the date of issue of the 2022 Series A Bonds. Pursuant to the Indenture and the Tax Certificate, the Agency has covenanted to comply with each applicable requirement of the Code necessary to qualify the 2022 Series A Bonds as obligations described in section 103(a) of the Code. In addition, the Agency has made certain representations and certifications in the Tax Certificate. We have not independently verified the accuracy of those certifications and representations.

Under existing law and assuming compliance with the tax covenants described herein, and the accuracy of certain representations and certifications made by the Agency described above, interest on the 2022 Series A Bonds is excluded from gross income for federal income tax purposes under Section 103 of the Code. We are also of the opinion that such amounts are not treated as a preference item in calculating the alternative minimum tax imposed under the Code.

We are also of the opinion that interest on the 2022 Bonds is exempt from personal income taxes of the State of California under present law.

Except as stated in the preceding two paragraphs, we express no opinion as to any other federal, state or local tax consequences of the ownership or disposition of the 2022 Bonds. Furthermore, we express no opinion as to any federal, state or local tax law consequences with respect to the 2022 Bonds, or the interest thereon, if any action is taken with respect to the 2022 Bonds or the proceeds thereof upon the advice or approval of other counsel

Very truly yours,

APPENDIX G

DEBT SERVICE REQUIREMENTS ON THE HYDROELECTRIC PROJECT BONDS

The following table shows the combined annual debt service required for the Hydroelectric Project Bonds to be Outstanding upon delivery of the 2022 Bonds. Principal amounts set forth in the table below include sinking fund redemptions.

Year Ended (July 1)	Outstanding Hydroelectric Project Bonds Debt Service(1)	2022 Bonds				Aggregate Annual Debt Service
		2022 Series A Bonds		2022 Series B Bonds		
		Principal	Interest	Principal	Interest	
2022						
2023						
2024						
2025						
2026						
2027						
2028						
2029						
2030						
2031						
2032						
Total						

(1) Excludes the [2008 Series A Bonds and] 2012 Series A Bonds which are being refunded with the proceeds of the 2022 Bonds. [Interest rate on the outstanding unhedged variable rate Hydroelectric Project Bonds is assumed to bear interest at 4.00% per annum.] ***{keep if not refunded}***

(2) Columns may not add to totals due to independent rounding.