REMARKETING MEMORANDUM

REMARKETED ISSUE—FULL BOOK-ENTRY ONLY **RATINGS: (See "RATINGS" herein)**

NORTHERN CALIFORNIA POWER AGENCY
Hydroelectric Project Number One Revenue Bonds

$85,160,000	**$2,105,000**
2008 Refunding Series A	**2008 Taxable Refunding Series B**
(Variable Rate Demand Bonds)	**(Taxable Variable Rate Demand Bonds)**

Dated: Date of Delivery **Due: July 1, as shown on the inside front 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 2008 Bonds. Investors are advised to read the entire Remarketing Memorandum to obtain information essential to the making of an informed investment decision. Capitalized terms used on this cover page not otherwise defined shall have the meanings set forth herein.

The Hydroelectric Project Number One Revenue Bonds, 2008 Refunding Series A (the "2008 Series A Bonds") and the Hydroelectric Project Number One Revenue Bonds, 2008 Taxable Refunding Series B (the "2008 Series B Bonds," and together with the 2008 Series A Bonds, the "2008 Bonds") were issued by the Northern California Power Agency ("NCPA") pursuant to an Indenture of Trust, dated as of March 1, 1985, as amended and supplemented, including as supplemented by the Sixteenth Supplemental Indenture of Trust, dated as of April 1, 2008, and the Seventeenth Supplemental Indenture of Trust, dated as of April 1, 2008 (collectively, the "Indenture"), by and between NCPA and U.S. Bank National Association, as successor trustee (the "Trustee"). This Remarketing Memorandum is furnished by NCPA to provide certain information in connection with the remarketing of the 2008 Bonds upon the mandatory tender thereof on September 10, 2014 in connection with the delivery of replacement Letters of Credit (as hereinafter defined) for such 2008 Bonds, as more fully described herein.

The 2008 Bonds were issued as fully registered bonds and are registered in the name of Cede & Co., as nominee of The Depository Trust Company, New York, New York ("DTC"). DTC acts as securities depository for the 2008 Bonds. Individual purchases of the 2008 Bonds will be made in book-entry form only. Purchasers of the 2008 Bonds will not receive physical certificates representing their interest in the 2008 Bonds purchased. Payments of principal or Tender Price of, premium, if any, and interest on the 2008 Bonds are payable by the Trustee to DTC, which is obligated in turn to remit such principal or Tender Price of, premium, if any, and interest to its DTC Participants for subsequent disbursement to the beneficial owners of the 2008 Bonds, as described herein.

The 2008 Series A Bonds currently bear interest in a Weekly Rate Period and will continue in a Weekly Rate Period until converted as provided herein. Pursuant to the Indenture, at the election of NCPA, the interest Rate Period for the 2008 Series A Bonds may be converted to a Daily Rate Period, a Short Term Rate Period, a Long Term Rate Period or an ARS Rate Period, as described herein.

The 2008 Series B Bonds currently bear interest in a Weekly Rate Period and will continue in a Weekly Rate Period until converted as provided herein. Pursuant to the Indenture, at the election of NCPA, the interest Rate Period for the 2008 Series B Bonds may be converted to a Long Term Rate Period, as described herein.

THIS REMARKETING MEMORANDUM IS NOT INTENDED TO PROVIDE INFORMATION WITH RESPECT TO THE 2008 BONDS (INCLUDING THE TERMS OF SUCH 2008 BONDS THAT CHANGE BASED ON THE INTEREST RATE PERIOD FOR SUCH 2008 BONDS) AFTER CONVERSION FROM A WEEKLY RATE PERIOD TO ANOTHER INTEREST RATE PERIOD OR IF SUCH 2008 BONDS ARE NO LONGER SECURED BY A LETTER OF CREDIT.

While bearing interest in a Weekly Rate Period, the 2008 Bonds will be delivered in denominations of $100,000 and any integral multiple of $5,000 in excess of $100,000. While bearing interest in a Weekly Rate Period, interest on the 2008 Bonds will be payable on January 1 and July 1 of each year. The first interest payment date following the remarketing and re-delivery of the 2008 Bonds as described herein will be January 1, 2015.

The 2008 Bonds are subject to optional, extraordinary and mandatory redemption prior to maturity, to mandatory tender on the dates and under the circumstances described herein and, while bearing interest in a Weekly Rate Period, to optional tender, all as described herein.

On September 10, 2014, two separate irrevocable direct-pay letters of credit, one for each Series of the 2008 Bonds (the "2008 Series A Letter of Credit" with respect to the 2008 Series A Bonds and the "2008 Series B Letter of Credit" with respect to the 2008 Series B Bonds, and each a "Letter of Credit") each issued by the Bank of Montreal, acting through its Chicago Branch (the "Bank"), are expected to replace the existing irrevocable direct-pay letters of credit issued on September 27, 2011, by Citibank, N.A. Payments of principal and redemption price of and interest on the 2008 Bonds of each Series will be supported by the related Letter of Credit each to be issued in favor of the Trustee for the benefit of the registered owners of the related Series of 2008 Bonds on the effective date of the related Letter of Credit. The Trustee will be instructed to draw upon the related Letter of Credit to pay such principal and redemption price of and interest on the related Series of 2008 Bonds. The Tender Agent may also draw funds under the related Letter of Credit to pay the Tender Price of the related Series of 2008 Bonds tendered for payment and not remarketed. Each of the 2008 Series A Letter of Credit and the 2008 Series B Letter of Credit has a scheduled termination date of September 9, 2019, subject to earlier termination under conditions described in the related Letter of Credit. See "THE LETTERS OF CREDIT AND REIMBURSEMENT AGREEMENTS" and "CERTAIN INFORMATION CONCERNING THE BANK" herein. See also "APPENDIX G – FORMS OF THE LETTERS OF CREDIT" hereto.

BMO Bank of Montreal

THE 2008 BONDS ARE SPECIAL, LIMITED OBLIGATIONS OF NCPA. THE 2008 BONDS OF EACH SERIES ARE PAYABLE SOLELY FROM DRAWINGS UNDER THE RELATED LETTER OF CREDIT AND THE TRUST ESTATE, AND ARE SECURED SOLELY BY DRAWINGS UNDER THE RELATED LETTER OF CREDIT AND 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, AND SHALL NOT CONSTITUTE A CHARGE AGAINST THE GENERAL CREDIT OF NCPA. THE 2008 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 2008 BONDS. NCPA HAS NO TAXING POWER.

On April 2, 2008, the date of the original issuance of the 2008 Bonds, Orrick, Herrington & Sutcliffe LLP ("Bond Counsel") rendered its opinion that based on an analysis of existing laws, regulations, rulings and court decisions, and assuming, among other matters, the accuracy of certain representations and compliance with certain covenants, (i) interest on the 2008 Series A Bonds was excluded from gross income of the owners thereof for federal income tax purposes pursuant to section 103 of the Internal Revenue Code of 1986 and was not a specific preference item for purposes of the federal individual or corporate alternative minimum taxes, although Bond Counsel observed that such interest was included in adjusted current earning when calculating corporate alternative minimum taxable income, and (ii) interest on the 2008 Bonds was exempt from personal income taxes of the State of California. The opinion of Bond Counsel has not been updated as of the date of this Remarketing Memorandum. A copy of the opinion of Bond Counsel delivered in connection with the original issuance of the 2008 Bonds is attached hereto as Appendix E. Orrick, Herrington & Sutcliffe LLP is serving as Bond Counsel to NCPA in connection with the remarketing of the 2008 Bonds. Certain legal matters will also be passed upon for NCPA by Meyers, Nave, Riback, Silver & Wilson, Sacramento, California, General Counsel to NCPA. Fulbright & Jaworski LLP, Los Angeles, California, is serving as disclosure counsel to NCPA in connection with the remarketing of the 2008 Bonds. Certain legal matters will be passed upon for the Bank by its United States counsel, Chapman and Cutler LLP, Chicago, Illinois.

Citigroup
Remarketing Agent

The date of this Remarketing Memorandum is August 29, 2014.

MATURITY SCHEDULE

$85,160,000 2008 Series A Bonds due July 1, 2032—Price 100%, CUSIP Number 664845BE3†

$2,105,000 2008 Series B Bonds due July 1, 2020—Price 100%, CUSIP Number 664845BF0†

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

NCPA Commissioners and Members

Management

General Manager	James Pope
Assistant General Manager, Finance and Administrative Services; Chief Financial Officer	Donna Stevener
Assistant General Manager, Legislative & Regulatory	Jane Cirrincione
Assistant General Manager, Power Management	David Dockham
Assistant General Manager, Generation Services	Ken Speer
Human Resources Manager	Vicki Cichocki

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

General Counsel to NCPA
Meyers, Nave, Riback,
Silver & Wilson
Sacramento, California

Bond Counsel
Orrick, Herrington
& Sutcliffe LLP
Los Angeles, California

Disclosure Counsel
Fulbright & Jaworski LLP
Los Angeles, California

Auditor
Moss Adams LLP
Portland, Oregon

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

Financial Advisor
Public Financial Management, Inc.
San Francisco, California

No dealer, broker, salesperson or any other person has been authorized by NCPA, the Project Participants or the Remarketing Agent to give any information or to make any representation, other than the information and representations contained herein, in connection with the remarketing of the 2008 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 Remarketing Memorandum does not constitute an offer to sell or the solicitation of an offer to buy, nor shall there be any sale of, the 2008 Bonds in any jurisdiction in which it is unlawful to make such offer, solicitation or sale. This Remarketing Memorandum is not to be construed as a contract with the purchasers of the 2008 Bonds.

Statements contained in this Remarketing Memorandum 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 relating to the Letters of Credit and the Bank, solely set forth under the captions "THE LETTERS OF CREDIT AND REIMBURSEMENT AGREEMENTS" (but excluding the information set forth thereunder under the subcaption "Alternate Credit Facility and Liquidity Facility") and "CERTAIN INFORMATION CONCERNING THE BANK" herein have been furnished by the Bank of Montreal, acting through its Chicago Branch, and neither NCPA nor the Project Participants make any representations with respect thereto or assume any responsibility therefor. The remaining information set forth herein has been furnished by NCPA, the Project Participants or other sources which are believed to be reliable, but is not guaranteed as to accuracy or completeness and is not to be construed as a representation by the Remarketing Agent. The information and expressions of opinion herein are subject to change without notice, and neither the delivery of this Remarketing Memorandum 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.

The Remarketing Agent has provided the following sentence for inclusion in this Remarketing Memorandum: The Remarketing Agent has reviewed the information in this Remarketing Memorandum in accordance with, and as part of, its responsibilities to investors under the federal securities laws as applied to the facts and circumstances of this transaction, but the Remarketing Agent does not guarantee the accuracy or completeness of such information.

CAUTIONARY STATEMENTS REGARDING FORWARD-LOOKING STATEMENTS IN THIS REMARKETING MEMORANDUM

Certain statements included or incorporated by reference in this Remarketing Memorandum 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," "DEVELOPMENTS IN THE CALIFORNIA ENERGY MARKETS" and "OTHER FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY" in this Remarketing Memorandum 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 Remarketing Memorandum 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, 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 described 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.

TABLE OF CONTENTS

Page

TABLE OF CONTENTS
(continued)

Page

TABLE OF CONTENTS
(continued)

Page

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REMARKETING MEMORANDUM
of
NORTHERN CALIFORNIA POWER AGENCY
Relating to its
Hydroelectric Project Number One Revenue Bonds

$85,160,000	**$2,105,000**
2008 Refunding Series A	**2008 Taxable Refunding Series B**
(Variable Rate Demand Bonds)	**(Variable Rate Demand Bonds)**

INTRODUCTION

This Introduction is not a summary of this Remarketing Memorandum, and is qualified in its entirety by reference to the more complete and detailed information included and referred to elsewhere in this Remarketing Memorandum. The reoffering of the 2008 Bonds to potential investors is made only by means of the entire Remarketing Memorandum. Capitalized terms used in this Introduction and not otherwise defined herein shall have the respective meanings assigned to them elsewhere in this Remarketing Memorandum. See "APPENDIX D – SUMMARY OF CERTAIN PROVISIONS OF THE INDENTURE – Certain Definitions."

General

This Remarketing Memorandum (which includes the cover page, the inside cover page, the table of contents and the appendices hereto) is furnished by the Northern California Power Agency ("NCPA") to provide certain information in connection with the remarketing of NCPA's outstanding $85,160,000 Hydroelectric Project Number One Revenue Bonds, 2008 Refunding Series A (the "2008 Series A Bonds") and its $2,105,000 Hydroelectric Project Number One Revenue Bonds, 2008 Taxable Refunding Series B (the "2008 Series B Bonds," and together with the 2008 Series A Bonds, the "2008 Bonds") upon the mandatory tender of such 2008 Bonds on September 10, 2014 in connection with the delivery of replacement Letters of Credit (as hereinafter defined) for such 2008 Bonds, as more fully described herein.

The 2008 Bonds were originally issued on April 2, 2008 pursuant to the provisions of Article 4 of the Joint Exercise of Powers Act, Chapter 5 of Division 7 of Title 1 of the Government Code of the State of California (the "Act") 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 and under and in accordance with an Indenture of Trust dated as of March 1, 1985, as amended and supplemented, including as supplemented by the Sixteenth Supplemental Indenture of Trust, dated as of April 1, 2008, and by the Seventeenth Supplemental Indenture of Trust, dated as of April 1, 2008 (collectively, the "Indenture"), by and between NCPA and U.S. Bank National Association (formerly U.S. Bank Trust National Association), as successor trustee (the "Trustee"), 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 eleven NCPA Members which have entered into the Third Phase Agreement with NCPA (collectively, the "Project Participants") relating to NCPA's Hydroelectric Project Number One (the "Project"), 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 2008 Bonds were issued to provide funds, together with other available moneys, to refund a portion of NCPA's then outstanding Hydroelectric Project Number One Revenue Bonds, 1998 Refunding

Series A (the "1998 Bonds" and such portion refunded, the "Refunded 1998 Bonds") and to pay costs of issuance of the 2008 Bonds and other costs relating to the refunding of the Refunded 1998 Bonds. The 1998 Bonds were originally issued pursuant to the Indenture for the purpose of refinancing a portion of the costs of the Project. The 2008 Bonds and all Hydroelectric Project Number One Revenue Bonds Outstanding under the Indenture are referred to herein as the "Hydroelectric Project Bonds."

NCPA

NCPA is a joint exercise of powers agency formed under 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 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 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 five principal Project Participants (the "Significant Share Project Participants"), representing in aggregate over 90% in Project Entitlement Percentages, are Alameda, Lodi, Palo Alto, Roseville and Santa Clara.

The Project

The Project consists of a 248.5 megawatt ("MW") hydroelectric project and related facilities, described under the caption "THE PROJECT." NCPA is entitled, under the Power Purchase Contract (i) to receive the electric output of the Project for 50 years from February 1982, with an option to purchase Project capacity and energy in excess of Calaveras's 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 used for load-following by NCPA to balance the baseload of the Project Participants and the generation from the Project and other resources available to the Project Participants through NCPA.

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. 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 2008 BONDS – Third Phase Agreement."

2008 Bonds

Under the Indenture, the 2008 Bonds are multi-modal bonds, and the term of each Series of the 2008 Bonds is divided into interest rate periods (each a "Rate Period"), as described herein. Each Series of the 2008 Bonds currently bears interest in a Weekly Rate Period and will continue in a Weekly Rate Period until converted as provided herein. Citigroup Global Markets Inc. currently serves as Remarketing

Agent for the 2008 Bonds. U.S. Bank National Association serves as Tender Agent for the 2008 Bonds. See "DESCRIPTION OF THE 2008 BONDS."

Pursuant to the Indenture, at the election of NCPA, the interest Rate Period for the 2008 Series A Bonds may be converted from a Weekly Rate Period to a Daily Rate Period, a Short Term Rate Period, a Long Term Rate Period or an ARS Rate Period, as described herein. If the interest Rate Period is converted from a Weekly Rate Period to any other interest Rate Period, the 2008 Series A Bonds will be subject to mandatory tender for purchase.

Pursuant to the Indenture, at the election of NCPA, the interest Rate Period for the 2008 Series B Bonds may be converted to a Long Term Rate Period, as described herein. If the interest Rate Period is converted from a Weekly Rate Period to a Long Term Rate Period, the 2008 Series B Bonds will be subject to mandatory tender for purchase.

THIS REMARKETING MEMORANDUM IS NOT INTENDED TO PROVIDE INFORMATION WITH RESPECT TO THE 2008 BONDS (INCLUDING THE TERMS OF SUCH 2008 BONDS THAT CHANGE BASED ON THE INTEREST RATE PERIOD FOR SUCH 2008 BONDS) AFTER CONVERSION FROM A WEEKLY RATE PERIOD TO ANOTHER INTEREST RATE PERIOD OR IF SUCH 2008 BONDS ARE NO LONGER SECURED BY A LETTER OF CREDIT.

Replacement of Letters of Credit

On September 10, 2014, two separate irrevocable direct-pay letters of credit, one for each Series of the 2008 Bonds (the "2008 Series A Letter of Credit" with respect to the 2008 Series A Bonds and the "2008 Series B Letter of Credit" with respect to the 2008 Series B Bonds, and each a "Letter of Credit" and collectively, the "Letters of Credit") each to be issued by the Bank of Montreal, acting through its Chicago Branch (the "Bank"), are expected to replace the existing irrevocable direct-pay letters of credit issued on September 27, 2011 by Citibank, N.A, for the related Series of 2008 Bonds. Payments of principal and redemption price of and interest on the 2008 Bonds of each Series will be supported by the related Letter of Credit each to be issued in favor of the Trustee for the benefit of the registered owners of the related Series of 2008 Bonds on the effective date of the related Letter of Credit. The Trustee will be instructed to draw upon the related Letter of Credit to pay such principal and redemption price of and interest on the related Series of 2008 Bonds. The Tender Agent may also draw funds under the related Letter of Credit to pay the Tender Price (as hereinafter defined) of the related Series of 2008 Bonds tendered for payment and not remarketed. Each of the Letters of Credit has a scheduled termination date of September 9, 2019, subject to earlier termination under conditions described in the related Letter of Credit. Each of the Letters of Credit may be extended or replaced by an alternate letter of credit or other facility or facilities providing credit support (a "Credit Facility") to pay principal of and interest on the 2008 Bonds of a Series and liquidity support (a "Liquidity Facility") to pay the Tender Price of 2008 Bonds of a Series tendered for purchase (other than Liquidity Provider 2008 Bonds, as defined herein, or 2008 Bonds held by or for the benefit of NCPA), as described herein.

NCPA and the Bank will enter into a Letter of Credit Reimbursement Agreement, dated as of September 1, 2014 (the "2008 Series A Reimbursement Agreement"), pursuant to which the 2008 Series A Letter of Credit will be issued and NCPA will be obligated to reimburse the Bank for amounts drawn under the 2008 Series A Letter of Credit subject to the terms and conditions therein. The 2008 Series A Letter of Credit constitutes a "2008 Series A Credit Facility" and a "2008 Series A Liquidity Facility" under the Indenture.

NCPA and the Bank will enter into a Letter of Credit Reimbursement Agreement, dated as of September 1, 2014 (the "2008 Series B Reimbursement Agreement" and together with the 2008 Series A

Reimbursement Agreement, the “Reimbursement Agreements”), pursuant to which the 2008 Series B Letter of Credit will be issued and NCPA will be obligated to reimburse the Bank for amounts drawn under the 2008 Series B Letter of Credit subject to the terms and conditions therein. The 2008 Series B Letter of Credit constitutes a “2008 Series B Credit Facility” and a “2008 Series B Liquidity Facility” under the Indenture.

See “THE LETTERS OF CREDIT AND REIMBURSEMENT AGREEMENTS” and “CERTAIN INFORMATION CONCERNING THE BANK.”

Security and Sources of Payment for the 2008 Bonds

The 2008 Bonds are special, limited obligations of NCPA. The 2008 Bonds of each Series are payable solely from, and secured solely by drawings under the related Letter of Credit and 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 2008 BONDS.”

THE 2008 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 2008 BONDS. NCPA HAS NO TAXING POWER.

2008 Debt Service Reserve Accounts

Pursuant to the Indenture, a Series Debt Service Reserve Account is established in the Debt Service Fund for each Series of the 2008 Bonds (each, a “2008 Debt Service Reserve Account”), designated the “Northern California Power Agency Hydroelectric Project Number One Revenue Bonds, 2008 Refunding Series A Debt Service Reserve Account” and the “Northern California Power Agency Hydroelectric Project Number One Revenue Bonds, 2008 Taxable Refunding Series B Debt Service Reserve Account,” respectively. **However, the Series A Debt Service Reserve Requirement and the 2008 Series B Debt Service Reserve Requirement (each, a “2008 Debt Service Reserve Requirement”) shall each be zero, and no amounts shall be required to be deposited and/or held therein until changed as provided under the Indenture.** See “SECURITY AND SOURCES OF PAYMENT FOR THE 2008 BONDS – 2008 Debt Service Reserve Accounts.”

Swap Agreement for the 2008 Bonds

In 2004, NCPA entered into an interest rate swap agreement (the “2004 Swap Agreement”) with Citigroup Financial Products Inc. (“CFPI”) in an initial notional amount of $85.16 million in anticipation of refunding the Refunded 1998 Bonds with the proceeds of the 2008 Bonds, for the purpose of converting the floating rate interest payments that NCPA is obligated to make with respect to the 2008 Series A Bonds into substantially fixed rate payments. Under certain circumstances, the 2004 Swap Agreement 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 2004 Swap Agreement, including any amounts payable upon early termination thereof, are payable from amounts on deposit in the General Reserve Account on a basis that is junior and subordinate to the payment of the Hydroelectric Project Bonds and are insured by National Public Finance Guarantee Corporation (formerly MBIA Insurance Corporation).

See “SECURITY AND SOURCES OF PAYMENT FOR THE 2008 BONDS—Swap Agreement.”

No Continuing Disclosure

While continuing in the Weekly Mode, the 2008 Bonds are exempt from the continuing disclosure requirements set forth in Securities and Exchange Commission Rule 15c2-12 (the "Rule") issued under the Securities Exchange Act of 1934, as amended.

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 Remarketing Memorandum, NCPA has relied upon certain information relating to the Project Participants furnished to NCPA by the Project Participants.

Attached to this Remarketing Memorandum is a summary of certain provisions of the Indenture. Copies of the Indenture and the Third Phase Agreement 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.

OTHER OBLIGATIONS OF NCPA

Each NCPA project is separately financed. As of June 30, 2014, in addition to the $401.2 million Hydroelectric Project Bonds outstanding under the Indenture, NCPA had outstanding approximately $48.1 million of Capital Facilities Revenue Bonds, $41.3 million of Geothermal Project Number 3 Revenue Bonds and $378.8 million of 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.

As described herein, NCPA has entered into the 2004 Swap Agreement for the purpose of converting the floating rate interest payments that NCPA is obligated to make with respect to the 2008 Series A Bonds into substantially fixed rate payments. The agreement by CFPI to make payments under the 2004 Swap Agreement does not affect NCPA's obligation to make payment of the 2008 Series A Bonds. Payments due from NCPA under the 2004 Swap Agreement, including any amounts payable upon early termination thereof, are payable from amounts on deposit in the General Reserve Account on a basis that is junior and subordinate to the payment of the Hydroelectric Project Bonds and are insured by National Public Finance Guarantee Corporation (formerly MBIA Insurance Corporation). See "SECURITY AND SOURCES OF PAYMENT FOR THE 2008 BONDS – Swap Agreement."

The 2008 Series A Bonds and the 2008 Series B Bonds are variable rate obligations and are each secured by a separate related Letter of Credit as described herein. Each Reimbursement Agreement for the related Letter of Credit obligates NCPA to repay the Bank for amounts drawn under the related Letter of Credit on a parity as to priority of payment and with respect to the lien on NCPA Revenues for the payment of the Hydroelectric Project Bonds. The interest rate payable by NCPA for unreimbursed draws under a Letter of Credit may be considerably higher than the current interest rate on the 2008 Series A Bonds and the 2008 Series B Bonds. While NCPA may attempt in such event to refinance the 2008 Series A Bonds and 2008 Series B Bonds to avoid this additional debt burden, there can be no assurance that NCPA will have access to the debt markets. See "THE LETTERS OF CREDIT AND REIMBURSEMENT AGREEMENTS."

DESCRIPTION OF THE 2008 BONDS

The following is a summary of certain provisions of the 2008 Series A Bonds and the 2008 Series B Bonds while in a Weekly Rate Period. Reference is made to the Indenture for a more detailed description of such provisions. The discussion herein is qualified by such reference. This Remarketing Memorandum is not intended to provide information with respect to the 2008 Bonds (including the terms of such 2008 Bonds which change based on the interest Rate Period for the 2008 Bonds) after Conversion from a Weekly Rate Period to another interest Rate Period or if such 2008 Bonds are no longer secured by a Letter of Credit.

General Bond Terms

Book-Entry Only System. The 2008 Bonds of each Series were issued as fully registered bonds, registered in the name of Cede & Co., as nominee for The Depository Trust Company, New York, New York ("DTC"). DTC acts as securities depository for the 2008 Bonds. Principal and Tender Price of, premium, if any, and interest on the 2008 Bonds are payable by the Trustee to DTC, which is obligated in turn to remit such principal and Tender Price of, premium, if any, and interest to its DTC Participants for subsequent disbursement to the beneficial owners of the 2008 Bonds. See "APPENDIX C – BOOK-ENTRY ONLY SYSTEM."

So long as Cede & Co. (or another nominee of DTC) is the registered owner of the 2008 Bonds, references herein to the Holders or registered owners of the 2008 Bonds will mean Cede & Co. (or such other nominee) as aforesaid, and will not mean the beneficial owners of the 2008 Bonds.

Authorized Denominations; Calculation and Payment of Interest. Each Series of 2008 Bonds currently bears interest at Weekly Rates in a Weekly Rate Period and will continue in a Weekly Rate Period until converted to another interest Rate Period, as described herein. During a Weekly Rate Period, the 2008 Bonds will be issued in Authorized Denominations of $100,000 and any integral multiple of $5,000 in excess of $100,000. During a Weekly Rate Period, interest on the 2008 Bonds is payable on each January 1 and July 1. The first interest payment date following the remarketing and re-delivery of the 2008 Bonds as described herein will be January 1, 2015. During a Weekly Rate Period, interest on the 2008 Bonds shall be computed on the basis of a 365-or 366-day year, as appropriate, and the actual number of days elapsed.

Maximum Interest Rate. At no time shall any 2008 Bonds (other than Liquidity Provider Bonds, as defined below) bear interest at a rate in excess of the Maximum Bond Interest Rate, which is the lesser of 12% per annum or the maximum rate permitted by law.

Letters of Credit; Liquidity Provider Bonds. On September 10, 2014, two separate irrevocable direct-pay Letters of Credit, each supporting a separate related Series of the 2008 Bonds, are expected to be issued by the Bank. The Trustee will be instructed to draw upon the related Letter of Credit to pay the principal and redemption price of and interest on the related Series of 2008 Bonds. The Tender Agent may also draw funds under the related Letter of Credit to pay the Tender Price (as hereinafter defined) of the related Series of 2008 Bonds tendered for payment and not remarketed. See "THE LETTERS OF CREDIT AND REIMBURSEMENT AGREEMENTS" and "CERTAIN INFORMATION CONCERNING THE BANK."

While the related Letter of Credit for the related Series of the 2008 Bonds is in effect, the Bank is considered the Holder of such related Series of 2008 Bonds for purposes of giving consents and directions to the Trustee under the Indenture.

There are a number of provisions in the Indenture relating to the terms of 2008 Bonds purchased by the Bank pursuant to a Letter of Credit ("Liquidity Provider Bonds") which are not described in this Remarketing Memorandum. All references to the terms of the 2008 Bonds in this Remarketing Memorandum describe only 2008 Bonds which are not owned by the Bank unless expressly indicated herein.

Interest Rates and Interest Rate Periods

Interest Rate Periods. The term of the 2008 Bonds shall be divided into consecutive interest Rate Periods selected by NCPA in the manner provided in the Indenture during which the 2008 Bonds of a Series shall bear interest at, in the case of the 2008 Series A Bonds, Daily Rates, Weekly Rates, Short Term Rates, Auction Period Rates or a Long Term Rate, and in the case of the 2008 Series B Bonds, Weekly Rates or a Long Term Rate. At any time, all 2008 Bonds of the same Series shall bear interest in the same interest Rate Period which, in the case of 2008 Series A Bonds, shall be a Daily Rate Period, a Weekly Rate Period, a Short Term Rate Period, a Long Term Rate Period or an ARS Rate Period, and, in the case of 2008 Series B Bonds, shall be a Weekly Rate Period or a Long Term Rate Period.

Each Series of the 2008 Bonds currently bears interest in a Weekly Rate Period. NCPA may elect that a Series of the 2008 Bonds be converted to another interest Rate Period available for such Series, subject to the satisfaction of certain conditions specified in the Indenture, including, in most cases, the prior written consent of the Bank and delivery of a Favorable Opinion of Bond Counsel in connection with a Conversion.

THIS REMARKETING MEMORANDUM IS NOT INTENDED TO PROVIDE INFORMATION WITH RESPECT TO THE 2008 BONDS (INCLUDING THE TERMS OF SUCH 2008 BONDS THAT CHANGE BASED ON THE INTEREST RATE PERIOD FOR SUCH 2008 BONDS) AFTER CONVERSION FROM A WEEKLY RATE PERIOD TO ANOTHER INTEREST RATE PERIOD OR IF SUCH 2008 BONDS ARE NO LONGER SECURED BY THE RELATED LETTER OF CREDIT.

Weekly Rate Period. During each Weekly Rate Period for the 2008 Bonds of a Series, the 2008 Bonds of such Series will bear interest at Weekly Rates. The Weekly Rate for each Series of 2008 Bonds shall be determined by the Remarketing Agent by no later than 5:00 p.m., New York City time, on Tuesday of each week during a Weekly Rate Period or if such day shall not be a Business Day, then on the next succeeding Business Day. The first Weekly Rate for each Weekly Rate Period shall be determined on or prior to the first day of such Weekly Rate Period and shall apply to the period commencing on the first day of such Weekly Rate Period and ending on and including the next succeeding Tuesday (whether or not a Business Day). Thereafter, each Weekly Rate shall apply to the period commencing on and including Wednesday (whether or not a Business Day) and ending on and including the next succeeding Tuesday (whether or not a Business Day), unless such Weekly Rate Period shall end on a day other than Tuesday, in which event the last Weekly Rate for such Weekly Rate Period shall apply to the period commencing on and including the Wednesday (whether or not a Business Day) preceding the last day of such Weekly Rate Period and ending on and including the last day of such Weekly Rate Period.

The Weekly Rate for each Series of 2008 Bonds shall be the rate of interest per annum determined by the Remarketing Agent to be the minimum interest rate which, if borne by such Series of 2008 Bonds, would enable the Remarketing Agent to sell all of the 2008 Bonds of such Series on the effective date of such rate at a price (without regarding accrued interest) equal to the principal amount thereof.

If the Remarketing Agent fails to establish a Weekly Rate for the 2008 Series A Bonds or 2008 Series B Bonds for any week, then the Weekly Rate for such Series of 2008 Bonds during such week shall be the same as the Weekly Rate for such Series of 2008 Bonds for the immediately preceding week, if the Weekly Rate for such Series of 2008 Bonds for such preceding week was determined by the Remarketing Agent. In the event the Remarketing Agent did not determine the Weekly Rate for the 2008 Series A Bonds or 2008 Series B Bonds for the immediately preceding week, or if the Weekly Rate for the 2008 Series A Bonds or the 2008 Series B Bonds determined by the Remarketing Agent shall be held to be invalid or unenforceable by a court of law, then the interest rate for the 2008 Series A Bonds or 2008 Series B Bonds, as applicable, for such week shall be equal to 110% of the SIFMA Swap Index, or if such index is no longer available, 85% of the interest rate on 30-day high grade unsecured commercial paper notes sold through dealers by major corporations as reported in The Wall Street Journal on the day the Weekly Rate for the 2008 Series A Bonds or 2008 Series B Bonds, as applicable, would otherwise be determined by the Remarketing Agent.

Conversion to an Alternate Interest Rate Period. NCPA may, with the prior written consent of the Bank, by written direction to the Trustee, with copies to the Tender Agent and the Remarketing Agent, elect to convert the 2008 Series A Bonds or 2008 Series B Bonds from the Weekly Rate Period to an alternate interest Rate Period. Upon such election and satisfaction of certain conditions, all of the 2008 Bonds of such Series will be subject to the alternate interest Rate Period. The written direction of NCPA must specify (i) the proposed effective date of the Conversion to any alternate interest Rate Period and (ii) the Tender Date for such Series of 2008 Bonds to be purchased, which shall be the proposed effective date of the Conversion to an alternate interest Rate Period. With respect to any Conversion to a Long Term Rate Period, the direction of NCPA shall specify the duration and last day of the Long Term Rate Period. In the case of the 2008 Series A Bonds, with respect to any Conversion to an ARS Rate Period, such direction of NCPA shall also specify the Initial Period, initial Auction Period, the first Auction Date and the first Interest Payment Date after the Conversion. In addition, the direction of NCPA shall be accompanied by (i) a Favorable Opinion of Bond Counsel and (ii) a form of the notice to be mailed by the Trustee to the Holders of the 2008 Bonds to be converted, as provided in the Indenture. A change to any alternate interest Rate Period may not take place unless, among other conditions, the prior written consent of the Bank has been obtained and a Favorable Opinion of Bond Counsel is delivered on the effective date of the alternate interest Rate Period.

The Trustee is required to give notice (by registered or certified mail, or by telecopy confirmed by registered or certified mail) of Conversion of either Series of 2008 Bonds to any new interest Rate Period not less than 30 days prior to the proposed effective date of such new interest Rate Period. **While the 2008 Bonds are registered in the name of Cede & Co., such notice shall be given only to DTC, and not to any Beneficial Owner of the 2008 Bonds.** Such notice will state (i) that the interest Rate Period on the 2008 Series A Bonds will be converted to a Daily Rate Period, a Long Term Rate Period, a Short Term Rate Period or an ARS Rate Period, or that the interest Rate Period on the 2008 Series B Bonds will be converted to a Long Term Rate Period, unless NCPA rescinds its election to convert the interest Rate Period or any condition precedent to such Conversion has not been satisfied; (ii) the proposed Conversion Date of such alternate interest Rate Period; (iii) that such Series of 2008 Bonds are subject to mandatory tender for purchase on such Conversion Date, whether or not the Conversion to such alternate interest Rate Period occurs; (iv) the applicable Tender Price; and (v) the procedures for such tender and purchase.

If any condition precedent to the Conversion of 2008 Bonds have not been satisfied, such Series of 2008 Bonds shall continue to be subject to mandatory tender for purchase on the date which would have been the Conversion Date. In such event, the interest Rate Period for such Series of 2008 Bonds shall not be converted and such Series of 2008 Bonds shall continue to bear interest in the Weekly Rate Period commencing on the date which would have been the effective date of the Conversion.

Rescission of Election to Convert to Alternate Interest Rate Period. Notwithstanding anything in the Indenture to the contrary, in connection with any Conversion of the interest Rate Period for either Series of 2008 Bonds, NCPA shall have the right to deliver to the Trustee on or prior to 10:00 a.m. on the Business Day preceding the proposed Conversion Date of any such Conversion, a notice to the effect that NCPA elects to rescind its election to make such Conversion. If NCPA rescinds its election to make such Conversion, then the 2008 Bonds of such Series shall continue to bear interest in a Weekly Rate Period, commencing on the date which would have been the effective date of the Conversion. In any event, if notice of a Conversion has been mailed to the Holders of such Series of 2008 Bonds and NCPA rescinds its election to make such Conversion, then such Series of 2008 Bonds shall continue to be subject to mandatory tender for purchase on the date which would have been the effective date of the Conversion.

Purchase of 2008 Bonds

Tenders of 2008 Bonds Are Subject to DTC Procedures. As long as the book-entry only system is in effect with respect to the 2008 Bonds, all tenders for purchase and deliveries of 2008 Bonds tendered for purchase or subject to mandatory tender under the provisions of the Indenture shall be made pursuant to DTC's procedures as in effect from time to time, and neither NCPA, the Bank, the Trustee, the Tender Agent nor the Remarketing Agent shall have any responsibility for or liability with respect to the implementation of such procedures. For a description of the tender procedures through DTC, see "APPENDIX C – BOOK-ENTRY ONLY SYSTEM."

Tender for Purchase Upon Election of Holder During Weekly Rate Period. During any Weekly Rate Period, the Holder of any 2008 Bond of a Series (other than a Liquidity Provider Bond) may elect to tender such 2008 Bond for purchase in an Authorized Denomination (provided that the amount of any such 2008 Bond of a Series not to be tendered for purchase shall also be in an Authorized Denomination) on any Business Day at a purchase price equal to the principal amount thereof, without premium, plus accrued interest to the applicable Tender Date (if the Tender Date is not an Interest Payment Date, in which event interest shall be paid to the Holder of such 2008 Bond as provided in the Indenture) (the "Tender Price"), upon delivery by the DTC Participant acting for such Holder to the Tender Agent, Trustee and Remarketing Agent of an irrevocable written notice which states the principal amount of the 2008 Bond tendered for purchase, the principal amount thereof to be purchased and the date on which such 2008 Bond is to be purchased, which date shall be a Business Day not prior to the seventh (7th) day next succeeding the date of the delivery of such notice to the Tender Agent. Any notice delivered to the Tender Agent after 4:00 p.m., New York City time, shall be deemed to have been received by the Tender Agent on the next succeeding Business Day.

The giving of notice by a Holder of a 2008 Bond to have its 2008 Bond purchased during a Weekly Rate Period shall constitute the irrevocable tender for purchase of such 2008 Bond regardless of whether that 2008 Bond is delivered to the Tender Agent for purchase on the relevant Tender Date.

Mandatory Tender for Purchase on First Day of Each Interest Rate Period. The 2008 Bonds of each Series shall be subject to mandatory tender for purchase at the applicable Tender Price on the first day of each interest Rate Period for the 2008 Bonds of such Series (or on the day which would have been the first day of an alternate interest Rate Period for such 2008 Bonds had one of the events specified in the Indenture not occurred which resulted in the interest Rate Period for such 2008 Bonds of such Series not being converted).

Mandatory Tender for Purchase Upon Substitution, Termination or Expiration of a Letter of Credit. If at any time the Trustee gives notice, in accordance with the Indenture, that the 2008 Bonds of a Series will, on the date specified in such notice, cease to be subject to purchase pursuant to the Liquidity Facility then in effect or cease to be paid from draws made under the Letter of Credit then in effect as a result of: (a) termination, substitution, or expiration of the term, as extended, of the Letter of Credit for such Series, including but not limited to termination at the option of NCPA in accordance with the terms of such Letter of Credit, or (b) the occurrence of a Mandatory Standby Tender, then, in the case of a termination or expiration of the term as extended, of the Letter of Credit for such Series of 2008 Bonds without replacement by an alternate Credit Facility or Liquidity Facility, on the fifth (5th) Business Day preceding any such expiration or termination and on the date of substitution or replacement in any case where an alternate Credit Facility or Liquidity Facility has been delivered to the Trustee, and in the case of a Mandatory Standby Tender, on the fifth (5th) Business Day following receipt of notice of the Bank directing such Mandatory Standby Tender, the 2008 Bonds of such Series shall be mandatorily tendered for purchase or deemed mandatorily tendered for purchase at the Tender Price.

Notice of Mandatory Tender for Purchase. In the case of any mandatory tender for purchase of the 2008 Bonds of a Series, the Trustee is required by the Indenture to give notice to the Holders of a Series of the 2008 Bonds (i) not later than 30 days prior to the proposed effective date of the alternate interest Rate Period for such Series, (ii) on or before the 30th day preceding the substitution, termination or expiration of the Letter of Credit securing such Series, or (iii) in the case of any Mandatory Standby Tender under the Letter of Credit securing such Series, as soon as reasonably possible, but no later than the Business Day, following the receipt by the Trustee of notice of the Mandatory Standby Tender.

Such notice will state:

(i) in the case of a mandatory tender for purchase on the a Conversion Date, the type of Rate Period to commence on such mandatory Tender Date;

(ii) in the case of a mandatory tender for purchase due to the termination, replacement or expiration of a Letter of Credit, that such Letter of Credit will expire, terminate or be replaced and that the 2008 Bonds of the applicable Series will no longer be payable from the related Letter of Credit, as appropriate, then in effect and that any rating applicable to the 2008 Bonds of such Series may be reduced or withdrawn;

(iii) that the Tender Price of any 2008 Bond of a Series subject to mandatory tender for purchase will be payable only upon surrender of that 2008 Bond of such Series to the Tender Agent pursuant to the Indenture;

(iv) that, provided that moneys sufficient to effect such purchase will have been provided through the remarketing of such 2008 Bonds of a Series by the Remarketing Agent or through the Letter of Credit or funds provided by NCPA (at its discretion), all 2008 Bonds of such Series subject to mandatory tender for purchase will be purchased on the mandatory Tender Date; and

(v) that if any Holder of a 2008 Bond of a Series subject to mandatory tender for purchase does not surrender that 2008 Bond of such Series to the Tender Agent for purchase on the mandatory Tender Date, then that 2008 Bond of such Series will be deemed to be an undelivered 2008 Bond, that no interest will accrue on that 2008 Bond of such Series on and after the mandatory Tender Date and that the Holder will have no rights under the Indenture other than to receive payment of the Tender Price.

Effect of Election to Tender or Mandatory Tender for Purchase of 2008 Bonds. The Tender Agent shall determine timely and proper delivery of 2008 Bonds of Series tendered for purchase and the proper endorsement of 2008 Bonds delivered. So long as the 2008 Bonds are held in book-entry only form, delivery of any such 2008 Bond of a Series in connection with any optional or mandatory tender for purchase shall be effected by the making of, or the irrevocable authorization to make, appropriate entries on the books of DTC or any DTC Participant to reflect the transfer of the beneficial ownership interest in such 2008 Bond to the account of the Tender Agent or to the account of a DTC Participant acting on behalf of the Tender Agent. If funds in the amount of the applicable Tender Price of a 2008 Bond tendered or deemed tendered for purchase in accordance with the Indenture are available for payment to the Holder of such 2008 Bond on the Tender Date, from and after the Tender Date, (i) such 2008 Bond shall be deemed to be purchased and shall no longer be deemed to be Outstanding under the Indenture, (ii) interest shall no longer accrue on such 2008 Bond; and (iii) funds in the amount of the Tender Price of such 2008 Bond will be held by the Tender Agent for the benefit of the Holder thereof, to be paid on delivery (and proper endorsement) of such 2008 Bond to the Tender Agent at its principal office for delivery of 2008 Bonds.

Sources of Funds for Payment of the Tender Price. Funds for the purchase of 2008 Bonds that have been tendered for purchase, whether at the option of the Holders or pursuant to the mandatory tender requirements described herein, will be provided from the following sources:

First, from the proceeds of the remarketing of such 2008 Bonds;

Second, from moneys received from draws on the related Letter of Credit; and

Third, from money made available by NCPA pursuant to the Indenture in its sole discretion.

Limited Obligation of NCPA. NCPA is not obligated to purchase 2008 Bonds tendered or deemed tendered for purchase pursuant to the Indenture if remarketing proceeds and payments under the related Letter of Credit received by the Tender Agent are insufficient to pay the Tender Price of such 2008 Bonds. The failure to pay the Tender Price of 2008 Bonds tendered or deemed tendered for purchase if such funds are insufficient is not an Event of Default under the Indenture.

Remarketing of 2008 Bonds. Upon a mandatory tender (other than a Mandatory Standby Tender) or notice of tender for purchase of 2008 Bonds of a Series, the Remarketing Agent will offer for sale and use its best efforts to sell such 2008 Bonds on the same date designated for purchase thereof and, if not remarketed on such date, thereafter until sold, at a price equal to par plus accrued interest in accordance with the Indenture. 2008 Bonds of a Series subject to a Mandatory Standby Tender will not be remarketed unless (1) the 2008 Bonds of such Series are converted to a Long Term Rate Period, or in the case of 2008 Series A Bonds, an ARS Rate Period, or (2) an alternate Liquidity Facility is in full force and effect, or unless the Liquidity Facility which respect to which such Mandatory Standby Tender was declared has been reinstated.

Inadequate Funds for Tenders. If sufficient funds are not available for the purchase of all 2008 Bonds of a Series tendered or deemed tendered and required to be purchased on any Tender Date, all such 2008 Bonds of such Series will bear interest at the Maximum Bond Interest Rate until all such 2008 Bonds of such Series Are purchased as required in accordance with the Indenture, and, if applicable, will be returned to their respective Owners. Notwithstanding any other provision of the Indenture, such failed purchase and return will not constitute an Event of Default under the Indenture.

Redemption of 2008 Bonds

Optional Redemption while in a Weekly Rate Period. While any Weekly Rate Period is in effect with respect to the 2008 Bonds, the 2008 Bonds are subject to redemption prior to their stated maturity, at the option of the NCPA, in whole or in part, in such amounts as may be specified by NCPA, on any date, at a redemption price equal to the principal amount of 2008 Bonds called for redemption, plus unpaid accrued interest to the date fixed for redemption, without premium.

Mandatory Sinking Fund Redemption – 2008 Series A Bonds. The 2008 Series A Bonds are also subject to mandatory redemption prior to their stated maturity, in part, on the dates and in the amounts set forth below (subject to adjustment in the event of optional redemption or extraordinary redemption), at a redemption price equal to the principal amount of the 2008 Series A Bonds to be redeemed, together with unpaid accrued interest thereon to the date fixed for redemption, without premium:

2008 Series A Bonds

Year (July 1)	Amount
2019	$ 1,520,000
2020	2,165,000
2021	2,255,000
2022	2,360,000
2023	2,600,000
2024	3,540,000
2025	3,450,000
2026	3,585,000
2027	3,730,000
2028	3,890,000
2029	13,175,000
2030	13,725,000
2031	14,285,000
2032†	14,880,000

†Final maturity.

Mandatory Sinking Fund Redemption – 2008 Series B Bonds. The 2008 Series B Bonds are also subject to mandatory redemption prior to their stated maturity, in part, on the dates and in the amounts set forth below (subject to adjustment in the event of optional redemption or extraordinary redemption), at a redemption price equal to the principal amount of the 2008 Series B Bonds to be redeemed, together with unpaid accrued interest thereon to the date fixed for redemption, without premium:

2008 Series B Bonds

Year (July 1)	Amount
2015	$275,000
2016	290,000
2017	305,000
2018	325,000
2019	725,000
2020†	185,000

†Final maturity.

Extraordinary Redemption. The 2008 Bonds are subject to redemption prior to their stated maturity, 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 2008 Bonds for redemption from insurance or condemnation proceeds shall expire 90 days following the receipt of such insurance or condemnation proceeds.

Selection of 2008 Bonds for Redemption. Whenever provision is made in the Indenture for the redemption of less than all of the 2008 Bonds of a Series, the Trustee shall select the 2008 Bonds of such Series to be redeemed from all 2008 Bonds of such Series subject to redemption and not previously called for redemption, in any manner which the Trustee in its sole discretion shall deem appropriate and fair, provided, however, that 2008 Bonds of each Series shall be redeemed in the following order of priority:

First: Any 2008 Bonds which are Liquidity Provider Bonds; and

Second: Any other 2008 Bonds.

Notice of Redemption. The Indenture requires the Trustee to give notice of the redemption of any 2008 Bonds by mailing a notice of redemption of such 2008 Bonds, postage prepaid, not less than 30 days before the redemption date, to the Holders of any 2008 Bonds or portions of 2008 Bonds which are to be redeemed, at their last address appearing upon the registry books. Among other things, such notice shall state that on the redemption date there shall become due and payable on each 2008 Bond to be redeemed the redemption price thereof, or the redemption price of the specified portions of the principal thereof in the case of 2008 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 shall cease to accrue and be payable. Receipt of such notice shall not be a condition precedent to such redemption and failure so to receive such notice or any defect in such notice shall not affect the validity of the proceedings for the redemption of 2008 Bonds. **So long as the 2008 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).**

Special Considerations Relating to the 2008 Bonds

Remarketing Agreement. NCPA has entered into a Remarketing Agreement for the 2008 Bonds, dated as of April 1, 2008 (the "Remarketing Agreement"), with Citigroup Global Markets Inc. as the Remarketing Agent (the "Remarketing Agent"). Under the Remarketing Agreement, the Remarketing Agent has agreed to use its best efforts to offer for sale all 2008 Bonds tendered in accordance with the provisions of the Indenture.

The Remarketing Agent is Paid by NCPA. The Remarketing Agent's responsibilities include determining the interest rate from time to time and remarketing 2008 Bonds that are optionally or mandatorily tendered by the owners thereof (subject, in each case, to the terms of the Remarketing Agreement), all as further described in this Remarketing Memorandum. The Remarketing Agent is appointed by NCPA and is paid by NCPA for its services. As a result, the interests of the Remarketing Agent may differ from those of existing Holders and potential purchasers of 2008 Bonds.

The Remarketing Agent Routinely Purchases Bonds for its Own Account. The Remarketing Agent acts as remarketing agent for a variety of variable rate demand obligations and, in its sole discretion, routinely purchases such obligations for its own account. The Remarketing Agent is permitted, but not obligated, to purchase tendered 2008 Bonds for its own account and, in its sole discretion, routinely acquires such tendered 2008 Bonds in order to achieve a successful remarketing of the 2008 Bonds (*i.e.*, because there otherwise are not enough buyers to purchase the 2008 Bonds) or for other reasons. However, the Remarketing Agent is not obligated to purchase 2008 Bonds, and may cease doing so at any time without notice. The Remarketing Agent may also make a market in the 2008 Bonds by routinely purchasing and selling 2008 Bonds other than in connection with an optional or mandatory tender and remarketing. Such purchases and sales may be at or below par. However, the Remarketing Agent is not required to make a market in the 2008 Bonds. The Remarketing Agent may also sell any 2008 Bonds it has purchased to one or more affiliated investment vehicles for collective ownership or enter into derivative arrangements with affiliates or others in order to reduce its exposure to the 2008 Bonds. The purchase of 2008 Bonds by the Remarketing Agent may create the appearance that there is greater third party demand for the 2008 Bonds in the market than is actually the case. The practices described above also may result in fewer 2008 Bonds being tendered in a remarketing.

Bonds May be Offered at Different Prices on Any Date Including an Interest Rate Determination Date. Pursuant to the Remarketing Agreement, the Remarketing Agent is required to determine the applicable rate of interest that, in its judgment, is the lowest rate that would permit the sale of the 2008 Bonds bearing interest at the applicable interest rate at par (without regard to accrued interest, if any) on and as of the applicable rate determination date. The interest rate will reflect, among other factors, the level of market demand for the 2008 Bonds (including whether the Remarketing Agent is willing to purchase 2008 Bonds for its own account). There may or may not be 2008 Bonds tendered and remarketed on a rate determination date, the Remarketing Agent may or may not be able to remarket any 2008 Bonds tendered for purchase on such date at par and the Remarketing Agent may sell 2008 Bonds at varying prices to different investors on such date or any other date. The Remarketing Agent is not obligated to advise purchasers in a remarketing if it does not have third party buyers for all of the 2008 Bonds at the remarketing price. In the event the Remarketing Agent owns any 2008 Bonds for its own account, it may, in its sole discretion in a secondary market transaction outside the tender process, offer such 2008 Bonds on any date, including the rate determination date, at a discount to par to some investors.

The Ability to Sell 2008 Bonds other than through Tender Process May Be Limited. The Remarketing Agent may buy and sell 2008 Bonds other than through the tender process. However, it is not obligated to do so and may cease doing so at any time without notice and may require Holders that wish to tender their 2008 Bonds to do so through the Tender Agent with appropriate notice. Thus, investors who purchase the 2008 Bonds, whether in a remarketing or otherwise, should not assume that they will be able to sell their 2008 Bonds other than by tendering the 2008 Bonds in accordance with the tender process.

Under Certain Circumstances, the Remarketing Agent May Be Removed, Resign or Cease Remarketing the 2008 Bonds, Without a Successor Being Named. Under certain circumstances the Remarketing Agent may be removed or have the ability to resign or cease its remarketing efforts. No removal shall take effect prior to the date that a successor remarketing agent has been appointed and has accepted such appointment. If the Remarketing Agent resigns without a successor having been named, the Trustee may assume such duties until a successor is appointed as described in the Indenture.

SECURITY AND SOURCES OF PAYMENT FOR THE 2008 BONDS

Letters of Credit

Payment of the principal or redemption price of, interest on, and (to the extent remarketing proceeds are insufficient therefor) the Tender Price of the 2008 Bonds of each Series will be made from proceeds of draws on the related Letter of Credit. Proceeds from the draws under the related Letter of Credit will be deposited into special accounts and used solely for such purpose. See "THE LETTERS OF CREDIT AND REIMBURSEMENT AGREEMENTS."

Pledge Effected by the Indenture

The 2008 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. Payment of the principal of and interest on, and the Tender Price of each Series of 2008 Bonds is additionally secured by the related Letter of Credit.

The 2008 Bonds and the interest thereon are payable solely from the funds provided therefor under the Indenture (including the related Letter of Credit) and shall not constitute a charge against the general credit of NCPA. The 2008 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 2008 Bonds. NCPA has no taxing power. Neither the payment of the principal of, or interest on, the 2008 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 shall not be individually liable on the 2008 Bonds or in respect of any undertakings by NCPA under the Indenture.

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:

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
- 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 2008 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 2008 BONDS – 2008 Debt Service Reserve Accounts.” Participating Bonds include the outstanding Hydroelectric Project Number One Revenue Bonds, 1992 Refunding Series A. All other Outstanding Hydroelectric Project Bonds are Non-Participating Bonds. The Indenture provides that Future Bonds will constitute 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.

(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.

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 – Rate Covenant.”

2008 Debt Service Reserve Accounts

The 2008 Debt Service Reserve Requirement for each Series of the 2008 Bonds shall be zero until changed as provided under the Indenture. Consequently, no funds are currently on deposit in or required to be maintained in the 2008 Debt Service Reserve Accounts.

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. The 2008 Bonds are Non-Participating Bonds. 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 of Trust authorizing the issuance of such Non-Participating Bonds. Amounts on deposit in the Debt Service Reserve Account secure only Participating Bonds. Amounts on deposit in any Series Debt Service Reserve Account (other than the applicable 2008 Series Debt Service Reserve Account in the event the Debt Service Reserve Requirement is hereafter changed from zero under the Indenture) do not secure in any manner the 2008 Bonds.

In the event that the 2008 Debt Service Reserve Requirement for a Series of 2008 Bonds is changed to an amount greater than zero pursuant to the Indenture, in lieu of the required deposits and transfers of money to such 2008 Debt Service Reserve Account, NCPA may cause to be deposited to such 2008 Debt Service Reserve Account a Financial Guaranty or Financial Guaranties in an amount equal to the difference between such 2008 Debt Service Reserve Requirement and the funds, if any, then on deposit in such 2008 Debt Service Reserve Account or being deposited in such 2008 Debt Service Reserve Account concurrently with such Financial Guaranty or Guaranties.

See “APPENDIX D – SUMMARY OF CERTAIN PROVISIONS OF THE INDENTURE – Application of Debt Service Reserve Accounts” for additional information regarding the 2008 Debt Service Reserve Accounts in the event such accounts are to be funded in the future.

Additional Bonds

NCPA may issue Hydroelectric Project Bonds under and secured by the Indenture ("Refunding Bonds") to refund bonds previously issued and Outstanding under and secured by the Indenture and may, although it does not 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 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 shall 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 2008 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 shall 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, nor does it require the Project Participants to do so.

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 shall 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 shall 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 (if applicable) 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.

Swap Agreement

NCPA entered into the 2004 Swap Agreement with CFPI in anticipation of refunding the Refunded 1998 Bonds with the proceeds of the 2008 Bonds, for the purpose of converting the floating rate interest payments NCPA is obligated to make with respect to the 2008 Series A Bonds into substantially fixed rate payments. In general, the terms of the 2004 Swap Agreement 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, NCPA will pay a fixed interest rate on the notional amount. In return, CFPI will pay a variable rate of interest under the 2004 Swap Agreement on a like notional amount. The agreement by CFPI to make payments under the 2004 Swap Agreement does not affect NCPA's obligation to make payment of the 2008 Bonds. Neither the Holders of the 2008 Bonds nor any other person other than NCPA will have any rights under the 2004 Swap Agreement or against CFPI.

Regularly scheduled payments due to CFPI from NCPA under the 2004 Swap Agreement are payable from amounts on deposit in the General Reserve Account on a basis which is junior and subordinate to the payment of the Hydroelectric Project Bonds. Under certain circumstances, the 2004 Swap Agreement is subject to early termination prior to the maturity of the 2008 Bonds, in which event NCPA may be obligated to make a substantial payment to CFPI under the 2004 Swap Agreement. Amounts due to CFPI upon any early termination of the 2004 Swap Transaction are payable from amounts on deposit in the General Reserve Account on a basis that is junior and subordinate to payment of the Hydroelectric Project Bonds.

The obligations of NCPA to make regularly scheduled payments and certain termination payments to CFPI under the 2004 Swap Agreement are insured by National Public Finance Guarantee Corporation (formerly MBIA Insurance Corporation).

Limitations on Remedies

The rights of the owners of the 2008 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 2008 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 2008 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.

THE LETTERS OF CREDIT AND REIMBURSEMENT AGREEMENTS

The 2008 Series A Letter of Credit and 2008 Series A Reimbursement Agreement

The following is a summary of certain provisions of the 2008 Series A Letter of Credit and the 2008 Series A Reimbursement Agreement. The 2008 Series A Letter of Credit will be substantially in the form attached as APPENDIX G.

The following summary does not purport to be a full and complete statement of the provisions of the 2008 Series A Letter of Credit or the 2008 Series A Reimbursement Agreement, each of which should be read in full for a complete understanding of all the terms and provisions thereof. Capitalized terms used in this summary and not defined in this summary or elsewhere in this Remarketing Memorandum shall have the meanings assigned to such terms in the 2008 Series A Letter of Credit or the 2008 Series A Reimbursement Agreement. In the event of any conflict between the 2008 Series A Reimbursement Agreement, or the 2008 Series A Letter of Credit and this Remarketing Memorandum with respect to a meaning assigned to a capitalized term used in this summary and not defined in this summary, the meaning set forth in the 2008 Series A Letter of Credit or the 2008 Series A Reimbursement Agreement shall control.

***2008 Series A Letter of Credit**.*

Payment of principal of and interest on the 2008 Series A Bonds which are Eligible Bonds is supported by the 2008 Series A Letter of Credit to be issued by the Bank pursuant to the 2008 Series A Reimbursement Agreement. Pursuant to the terms of the 2008 Series A Letter of Credit, the Trustee and Tender Agent, as applicable, under the Indenture, are entitled to draw thereunder to pay the principal of, the redemption price and interest on the 2008 Series A Bonds which are Eligible Bonds and to pay the purchase price of the 2008 Series A Bonds which are Eligible Bonds tendered but unsuccessfully remarketed.

The 2008 Series A Letter of Credit irrevocably authorizes draws in accordance with its terms in an aggregate amount not exceeding $90,815,558 (as reduced and reinstated from time to time in accordance with the provisions of such 2008 Series A Letter of Credit, the "Stated Amount"), consisting of (i) the amount of $85,160,000, which may be drawn upon with respect to payment of the unpaid principal amount of, or portion of the purchase price corresponding to the principal of, the 2008 Series A Bonds and (ii) the amount of $5,655,558, which may be drawn upon with respect to the payment of up to 202 days' accrued interest on the 2008 Series A Bonds, in each case assuming a maximum interest rate of 12% per annum based on a year of 365 days.

The 2008 Series A Letter of Credit will terminate on the Termination Date. As used herein, *"Termination Date"* means 5:00 p.m. New York City time on the earliest of: (i) September 9, 2019 (the *"Expiration Date"*); provided that, if on or before such date, or such later date to which the term of the 2008 Series A Letter of Credit is extended, as provided in the 2008 Series A Letter of Credit, the Bank provides written notice to the Trustee and Tender Agent that the 2008 Series A Letter of Credit shall be extended, the term of the 2008 Series A Letter of Credit shall be extended to the date provided in such notice (any date to which the Expiration Date has been extended as provided in the 2008 Series A Letter of Credit may be extended in a like manner); (ii) the date on which the Bank receives notice from the Trustee stating that the principal amount of and interest on all of the 2008 Series A Bonds has been paid in full or deemed paid in full in accordance with the provisions of the Original Indenture and the Supplemental Indenture; (iii) the date on which the Bank receives notice from the Trustee stating that all of the 2008 Series A Bonds have been converted to a rate other than a Covered Rate under the Supplemental Indenture, but only after the Bank has honored all Drawings made in strict conformity with the terms of the 2008 Series A Letter of Credit on or before such date; (iv) the date on which the Bank receives notice from the Trustee stating that an Alternate Credit Facility has become effective under the Supplemental Indenture in substitution for the 2008 Series A Letter of Credit, but only after the Bank has honored all Drawings made in strict conformity with the terms of the 2008 Series A Letter of Credit on or before such date; or (v) the date which is six (6) Business Days after the Trustee and Tender Agent have received a written notice as described in the 2008 Series A Letter of Credit that an Event of Default has been declared under the 2008 Series A Reimbursement Agreement from the Bank. In the event the Expiration Date shall not be a Business Day, then the 2008 Series A Letter of Credit shall expire on the next succeeding Business Day.

2008 Series A Reimbursement Agreement.

Set forth below is a summary of the events of default and remedies sections of the 2008 Series A Reimbursement Agreement. This summary does not purport to be complete or to cover all relevant provisions of the 2008 Series A Reimbursement Agreement. Reference is made to the 2008 Series A Reimbursement Agreement for the details of the provisions thereof.

Events of Default. The occurrence of any of the following events (including the expiration of any specified time) shall constitute an "Event of Default" under the 2008 Series A Reimbursement Agreement unless waived by the Bank in writing:

(a) Failure of NCPA to pay when due any amount owed under the 2008 Series A Reimbursement Agreement, under the Fee Letter or under any of the other Related Documents or the principal of or the interest on the Bonds or any Parity Debt; *provided, however,* that with respect to any amounts owed to the Bank pursuant to the Fee Letter, such failure shall not constitute an Event of Default unless such failure continues for three (3) Business Days following the date such amount became due and payable.

(b) Failure of NCPA to observe certain covenants set forth in the 2008 Series A Reimbursement Agreement.

(c) Failure of NCPA to observe or perform any of the covenants, conditions or provisions of the 2008 Series A Reimbursement Agreement or any of the Related Documents (other than as specified in (a) or (b) above or (i) below) or the Governing Documents and the continuance of such default for thirty (30) days after the earlier of (x) the date on which notice thereof has been given to NCPA by the Bank or (y) the date on which any officer of NCPA obtained actual knowledge thereof.

(d) Any representation or warranty made by NCPA in the 2008 Series A Reimbursement Agreement, in any Related Document or in any certificate, financial or other statement furnished by NCPA pursuant to the 2008 Series A Reimbursement Agreement or any of the Related Documents shall prove to have been untrue in any material respect when made.

(e) The occurrence and continuation of an Indenture Event of Default, an "Event of Default" as defined in any of the Related Documents under any of the Related Documents.

(f) Default by NCPA in the payment of any amount due in respect of any Parity Debt (including, without limitation, any regularly scheduled payments on any Interest Rate Protection Agreement which constitute Parity Debt), as and when the same shall become due, or default under any mortgage, agreement or other instrument under or pursuant to which such Parity Debt is incurred or issued, and continuance of such default beyond the period of grace, if any, allowed with respect thereto, or the occurrence of any act or omission by NCPA under any such mortgage, agreement or other instrument which results in such Parity Debt becoming, or being capable of becoming, immediately due and payable (or, with respect to any Interest Rate Protection Agreement, which results in such Interest Rate Protection Agreement being terminated early or being capable of being terminated early).

(g) The entry or filing of any judgment, writ or warrant of attachment or of any similar process in an amount in excess of $10,000,000 against NCPA relating to the Trust Estate or against the Project and failure of NCPA to vacate, bond, stay, appeal (if such appeal acts to stay the enforcement of such judgment, writ or warrant of attachment), or contest in good faith such judgment, writ, warrant of attachment or other process for a period of 60 days or failure to pay or satisfy such judgment within 60 days.

(h) The occurrence of an Event of Insolvency with respect to NCPA.

(i) The rating assigned to the Bonds or any Parity Debt (without regard to third party credit enhancement) by Moody's, Fitch or S&P, in each case to the extent then providing a rating at the request of NCPA, shall be withdrawn, suspended or falls to or below "Baa3" by Moody's, "BBB-" by Fitch or "BBB-" by S&P.

(j) (i) any material provision of the 2008 Series A Reimbursement Agreement, the Fee Letter, the Act or any of the Related Documents or any of the Governing Documents ceases to be valid and binding on NCPA for any reason or the 2008 Series A Reimbursement Agreement, the Fee Letter, the Act or any of the other Related Documents or any of the Governing Documents is declared null and void, or the validity or enforceability thereof is contested by NCPA or any officer of NCPA or by the Governmental Authority having jurisdiction or NCPA denies it has any or further liability under the 2008 Series A Reimbursement Agreement, the Fee Letter, the Act or any of the other Related Documents or any of the Governing Documents, or such document is cancelled or terminated without the prior written consent of the Bank, or NCPA shall seek an adjudication that the 2008 Series A Reimbursement Agreement, any other Related Document to which NCPA is a party, or any of the Governing Documents or any provision of the Indenture relating to the security for the Bonds or the Obligations, NCPA's ability to pay the Obligations or perform its obligations under the 2008 Series A Reimbursement Agreement or the rights and remedies of the Bank, is not valid and binding on NCPA; or (ii) any pledge or security interest created by the Indenture or the 2008 Series A Reimbursement Agreement to secure any amount due under any Bonds, the Bank Bonds, the 2008 Series A Reimbursement Agreement or the Fee Letter shall fail to be fully enforceable or fail to have the priority required thereunder.

(k) Any actual seizure, vesting or intervention, by or under a Governmental Authority by which NCPA's management is displaced or its authority or control of its business relating to the Project is curtailed.

(l) Attachment or restraint of any funds or other property relating to the Trust Estate or the Project which may be in, or come into, the possession or control of the Trustee or the Bank or of any third party acting on the Bank's behalf, for the account or benefit of NCPA, or, except for limitations on remedies available against public agencies such as NCPA in the State, the issuance of any order of any court or other legal process against the same.

(m) An event has occurred and is continuing which has or is having a Material Adverse Effect.

(n) the powers of NCPA shall be limited in any way or the Indenture shall be modified or amended in any way without the prior written consent of the Bank, in either case, which prevents NCPA from fixing, charging or collecting rates and charges for the use and services of the Project in any amount sufficient to pay its debts as they become due.

(o) NCPA shall (i) default on the payment of the principal of or interest on any Debt (other than Parity Debt) including, without limitation, any regularly scheduled payments on Interest Rate Protection Agreements, aggregating in excess of $10,000,000, beyond the period of grace, if any, provided in the instrument or agreement under which such Debt (other than Parity Debt) was created or incurred; or (ii) default in the observance or performance of any agreement or condition relating to any Debt (other than Parity Debt) aggregating in excess of $10,000,000, or contained in any instrument or agreement evidencing, securing or relating thereto, or any other default, event of default or similar event shall occur or condition exist, the effect of which default, event of default or similar event or condition is to permit (determined without regard to whether any notice is required) any such Debt to become immediately due and payable in full as the result of the acceleration, mandatory redemption or mandatory tender of such Debt.

Rights and Remedies Upon the Occurrence of an Event of Default. (a) Upon the occurrence and continuation of an Event of Default, the Bank, in its sole discretion, (i) may, by notice to NCPA, the Tender Agent and the Trustee, declare the obligations of NCPA under the 2008 Series A Reimbursement Agreement (other than amounts owed on Bank Bonds) to be immediately due and payable, and the same shall thereupon become immediately due and payable (*provided* that, the obligations of NCPA under the 2008 Series A Reimbursement Agreement shall be and become automatically and immediately due and payable without such notice upon the occurrence of an Event of Default described in paragraph (h) under the subcaption "Events of Default" above), without demand, presentment, protest or further notice of any kind, all of which are expressly waived by NCPA under the 2008 Series A Reimbursement Agreement, (ii) may deliver to the Trustee and the Tender Agent written notice as described in the 2008 Series A Letter of Credit that an Event of Default has been declared under the 2008 Series A Reimbursement Agreement and that the 2008 Series A Letter of Credit will terminate six (6) Business Days after receipt of such notice together with a written request that the Trustee call the Bonds for mandatory tender for purchase, (iii) may deliver to the Trustee and the Tender Agent written notices as described in the 2008 Series A Letter of Credit that the Interest Portion shall not be reinstated following an Interest Drawing, (iv) may cure any default, event of default or event of nonperformance under the 2008 Series A Reimbursement Agreement or under any of the Related Documents (in which event NCPA shall reimburse the Bank therefor pursuant to the 2008 Series A Reimbursement Agreement), (v) may exercise its banker's lien, or right of set-off with respect to the Project, (vi) may deliver written notice to the Trustee directing that all Bank Bonds be redeemed immediately pursuant to the Supplemental Indenture on the Business Day immediately succeeding the date on which the Trustee shall have received such notice, (vii) may proceed to protect its right by suit in equity, action at law or other appropriate proceedings for specific performance of any covenant or agreement of NCPA contained in the 2008 Series A Reimbursement Agreement or (viii) may exercise any other rights or remedies available under any Related Document, any other agreement or at law or in equity. The rights and remedies of the Bank specified in the 2008 Series A Reimbursement Agreement are for the sole and exclusive benefit, use and protection of the Bank, and the Bank is entitled, but shall have no duty or obligation to NCPA, the Trustee, the Tender Agent, the Bondholders or otherwise, (1) to exercise or to refrain from exercising any right or remedy reserved to the Bank under the 2008 Series A Reimbursement Agreement, or (2) to cause the Trustee or any other party to exercise or to refrain from exercising any right or remedy available to it under any of the Related Documents.

(b) From and after the occurrence of an Event of Default, all amounts owing to the Bank under the 2008 Series A Reimbursement Agreement and amounts owing on any Bank Bonds shall bear interest at the Default Rate.

If any Event of Default shall occur, then and in every such case the Bank shall be entitled to proceed to protect and enforce its rights by such appropriate judicial proceeding as it may deem most effectual to protect and enforce any such right, either by suit, in equity, or by action at law, whether for the specific performance of any covenant or agreement contained in the 2008 Series A Reimbursement Agreement, in aid of the exercise of any power granted in the 2008 Series A Reimbursement Agreement, or to enforce any other legal or equitable right vested in the Bank by the 2008 Series A Reimbursement Agreement, the Bank Bonds, the Related Documents or by law. The provisions of the 2008 Series A Reimbursement Agreement shall be a contract with the Bank and the duties of NCPA shall be enforceable, subject to judicial discretion and the availability of equitable remedies, by the Bank by mandamus or other appropriate suit, action, or proceeding in any court of competent jurisdiction.

The 2008 Series B Letter of Credit and 2008 Series B Reimbursement Agreement

The following is a summary of certain provisions of the 2008 Series B Letter of Credit and the 2008 Series B Reimbursement Agreement. The 2008 Series B Letter of Credit will be substantially in the form attached as APPENDIX G.

The following summary does not purport to be a full and complete statement of the provisions of the 2008 Series B Letter of Credit or the 2008 Series B Reimbursement Agreement, each of which should be read in full for a complete understanding of all the terms and provisions thereof. Capitalized terms used in this summary and not defined in this summary or elsewhere in this Remarketing Memorandum shall have the meanings assigned to such terms in the 2008 Series B Letter of Credit or the 2008 Series B Reimbursement Agreement. In the event of any conflict between the 2008 Series B Reimbursement Agreement or the 2008 Series B Letter of Credit and this Remarketing Memorandum with respect to a meaning assigned to a capitalized term used in this summary and not defined in this summary, the meaning set forth in the 2008 Series B Letter of Credit or the 2008 Series B Reimbursement Agreement shall control.

2008 Series B Letter of Credit*.*

Payment of principal of and interest on the 2008 Series B Bonds which are Eligible Bonds is supported by the 2008 Series B Letter of Credit to be issued by the Bank pursuant to the 2008 Series B Reimbursement Agreement. Pursuant to the terms of the 2008 Series B Letter of Credit, the Trustee and Tender Agent, as applicable, under the Indenture, are entitled to draw thereunder to pay the principal of, the redemption price and interest on the 2008 Series B Bonds which are Eligible Bonds and to pay the purchase price of the 2008 Series B Bonds which are Eligible Bonds tendered but unsuccessfully remarketed.

The 2008 Series B Letter of Credit irrevocably authorizes draws in accordance with its terms in an aggregate amount not exceeding $2,244,796 (as reduced and reinstated from time to time in accordance with the provisions of such 2008 Series B Letter of Credit, the "Stated Amount"), consisting of (i) the amount of $2,105,000, which may be drawn upon with respect to payment of the unpaid principal amount of, or portion of the purchase price corresponding to the principal of, the 2008 Series B Bonds and (ii) the amount of $139,796, which may be drawn upon with respect to the payment of up to 202 days' accrued interest on the 2008 Series B Bonds, in each case assuming a maximum interest rate of 12% per annum based on a year of 365 days.

The 2008 Series B Letter of Credit will terminate on the Termination Date. As used herein, *"Termination Date"* means 5:00 p.m. New York City time on the earliest of: (i) September 9, 2019 (the *"Expiration Date"*); provided that, if on or before such date, or such later date to which the term of the 2008 Series B Letter of Credit is extended, as provided in the 2008 Series B Letter of Credit, the Bank provides written notice to the Trustee and Tender Agent that the 2008 Series B Letter of Credit shall be extended, the term of the 2008 Series B Letter of Credit shall be extended to the date provided in such notice (any date to which the Expiration Date has been extended as provided in the 2008 Series B Letter of Credit may be extended in a like manner); (ii) the date on which the Bank receives notice from the Trustee stating that the principal amount of and interest on all of the 2008 Series B Bonds has been paid in full or deemed paid in full in accordance with the provisions of the Original Indenture and the Supplemental Indenture; (iii) the date on which the Bank receives notice from the Trustee stating that all of the 2008 Series B Bonds have been converted to a rate other than the Covered Rate under the Supplemental Indenture, but only after the Bank has honored all Drawings made in strict conformity with the terms of the 2008 Series B Letter of Credit; (iv) the date on which the Bank receives notice from the Trustee stating that an Alternate Credit Facility has become effective under the Supplemental Indenture in substitution for the 2008 Series B Letter of Credit, but only after the Bank has honored all Drawings made in strict conformity with the terms of the 2008 Series B Letter of Credit on or before such date; or (v) the date which is six (6) Business Days after the Trustee and Tender Agent have received a written notice as described in the 2008 Series B Letter of Credit that an Event of Default has been declared under the 2008 Series B Reimbursement Agreement from the Bank. In the event the Expiration Date shall not be a Business Day, then the 2008 Series B Letter of Credit shall expire on the next succeeding Business Day.

2008 Series B Reimbursement Agreement.

Set forth below is a summary of the events of default and remedies sections of the 2008 Series B Reimbursement Agreement. This summary does not purport to be complete or to cover all relevant provisions of the 2008 Series B Reimbursement Agreement. Reference is made to the 2008 Series B Reimbursement Agreement for the details of the provisions thereof.

Events of Default. The occurrence of any of the following events (including the expiration of any specified time) shall constitute an "Event of Default" under the 2008 Series B Reimbursement Agreement unless waived by the Bank in writing:

(a) Failure of NCPA to pay when due any amount owed under the 2008 Series B Reimbursement Agreement, under the Fee Letter or under any of the other Related Documents or the principal of or the interest on the Bonds or any Parity Debt; *provided, however,* that with respect to any amounts owed to the Bank pursuant to the Fee Letter, such failure shall not constitute an Event of Default unless such failure continues for three (3) Business Days following the date such amount became due and payable.

(b) Failure of NCPA to observe certain covenants set forth in the 2008 Series B Reimbursement Agreement.

(c) Failure of NCPA to observe or perform any of the covenants, conditions or provisions of the 2008 Series B Reimbursement Agreement or any of the Related Documents (other than as specified in (a) or (b) above or (i) below) or the Governing Documents and the continuance of such default for thirty (30) days after the earlier of (x) the date on which notice thereof has been given to NCPA by the Bank or (y) the date on which any officer of NCPA obtained actual knowledge thereof.

(d) Any representation or warranty made by NCPA in the 2008 Series B Reimbursement Agreement, in any Related Document or in any certificate, financial or other statement furnished by NCPA pursuant to the 2008 Series B Reimbursement Agreement or any of the Related Documents shall prove to have been untrue in any material respect when made.

(e) The occurrence and continuation of an Indenture Event of Default, an "Event of Default" as defined in any of the Related Documents under any of the Related Documents.

(f) Default by NCPA in the payment of any amount due in respect of any Parity Debt (including, without limitation, any regularly scheduled payments on any Interest Rate Protection Agreement which constitute Parity Debt), as and when the same shall become due, or default under any mortgage, agreement or other instrument under or pursuant to which such Parity Debt is incurred or issued, and continuance of such default beyond the period of grace, if any, allowed with respect thereto, or the occurrence of any act or omission by NCPA under any such mortgage, agreement or other instrument which results in such Parity Debt becoming, or being capable of becoming, immediately due and payable (or, with respect to any Interest Rate Protection Agreement, which results in such Interest Rate Protection Agreement being terminated early or being capable of being terminated early).

(g) The entry or filing of any judgment, writ or warrant of attachment or of any similar process in an amount in excess of $10,000,000 against NCPA relating to the Trust Estate or against the Project and failure of NCPA to vacate, bond, stay, appeal (if such appeal acts to stay the enforcement of such judgment, writ or warrant of attachment), or contest in good faith such judgment, writ, warrant of attachment or other process for a period of 60 days or failure to pay or satisfy such judgment within 60 days.

(h) The occurrence of an Event of Insolvency with respect to NCPA.

(i) The rating assigned to the Bonds or any Parity Debt (without regard to third party credit enhancement) by Moody's, Fitch or S&P, in each case to the extent then providing a rating at the request of NCPA, shall be withdrawn, suspended or falls to or below "Baa3" by Moody's, "BBB-" by Fitch or "BBB-" by S&P.

(j) (i) any material provision of the 2008 Series B Reimbursement Agreement, the Fee Letter, the Act or any of the Related Documents or any of the Governing Documents ceases to be valid and binding on NCPA for any reason or the 2008 Series B Reimbursement Agreement, the Fee Letter, the Act or any of the other Related Documents or any of the Governing Documents is declared null and void, or the validity or enforceability thereof is contested by NCPA or any officer of NCPA or by the Governmental Authority having jurisdiction or NCPA denies it has any or further liability under the 2008 Series B Reimbursement Agreement, the Fee Letter, the Act or any of the other Related Documents or any of the Governing Documents, or such document is cancelled or terminated without the prior written consent of the Bank, or NCPA shall seek an adjudication that the 2008 Series B Reimbursement Agreement, any other Related Document to which NCPA is a party, or any of the Governing Documents or any provision of the Indenture relating to the security for the Bonds or the Obligations, NCPA's ability to pay the Obligations or perform its obligations under the 2008 Series B Reimbursement Agreement or the rights and remedies of the Bank, is not valid and binding on NCPA; or (ii) any pledge or security interest created by the Indenture or the 2008 Series B Reimbursement Agreement to secure any amount due under any Bonds, the Bank Bonds, the 2008 Series B Reimbursement Agreement or the Fee Letter shall fail to be fully enforceable or fail to have the priority required thereunder.

(k) Any actual seizure, vesting or intervention, by or under a Governmental Authority by which NCPA's management is displaced or its authority or control of its business relating to the Project is curtailed.

(l) Attachment or restraint of any funds or other property relating to the Trust Estate or the Project which may be in, or come into, the possession or control of the Trustee or the Bank or of any third party acting on the Bank's behalf, for the account or benefit of NCPA, or, except for limitations on remedies available against public agencies such as NCPA in the State, the issuance of any order of any court or other legal process against the same.

(m) An event has occurred and is continuing which has or is having a Material Adverse Effect.

(n) the powers of NCPA shall be limited in any way or the Indenture shall be modified or amended in any way without the prior written consent of the Bank, in either case, which prevents NCPA from fixing, charging or collecting rates and charges for the use and services of the Project in any amount sufficient to pay its debts as they become due.

(o) NCPA shall (i) default on the payment of the principal of or interest on any Debt (other than Parity Debt) including, without limitation, any regularly scheduled payments on Interest Rate Protection Agreements, aggregating in excess of $10,000,000, beyond the period of grace, if any, provided in the instrument or agreement under which such Debt (other than Parity Debt) was created or incurred; or (ii) default in the observance or performance of any agreement or condition relating to any Debt (other than Parity Debt) aggregating in excess of $10,000,000, or contained in any instrument or agreement evidencing, securing or relating thereto, or any other default, event of default or similar event shall occur or condition exist, the effect of which default, event of default or similar event or condition is to permit (determined without regard to whether any notice is required) any such Debt to become immediately due and payable in full as the result of the acceleration, mandatory redemption or mandatory tender of such Debt.

Rights and Remedies Upon the Occurrence of an Event of Default. (a) Upon the occurrence and continuation of an Event of Default, the Bank, in its sole discretion, (i) may, by notice to NCPA, the Tender Agent and the Trustee, declare the obligations of NCPA under the 2008 Series B Reimbursement Agreement (other than amounts owed on Bank Bonds) to be immediately due and payable, and the same shall thereupon become immediately due and payable (*provided* that, the obligations of NCPA under the 2008 Series B Reimbursement Agreement shall be and become automatically and immediately due and payable without such notice upon the occurrence of an Event of Default described in paragraph (h) under the subcaption "Events of Default" above), without demand, presentment, protest or further notice of any kind, all of which are expressly waived by NCPA under the 2008 Series B Reimbursement Agreement, (ii) may deliver to the Trustee and the Tender Agent written notice as described in the 2008 Series B Letter of Credit that an Event of Default has been declared under the 2008 Series B Reimbursement Agreement and that the 2008 Series B Letter of Credit will terminate six (6) Business Days after receipt of such notice together with a written request that the Trustee call the Bonds for mandatory tender for purchase, (iii) may deliver to the Trustee and the Tender Agent written notices as described in the 2008 Series B Letter of Credit that the Interest Portion shall not be reinstated following an Interest Drawing, (iv) may cure any default, event of default or event of nonperformance under the 2008 Series B Reimbursement Agreement or under any of the Related Documents (in which event NCPA shall reimburse the Bank therefor pursuant to the 2008 Series B Reimbursement Agreement), (v) may exercise its banker's lien, or right of set-off with respect to the Project, (vi) may deliver written notice to the Trustee directing that all Bank Bonds be redeemed immediately pursuant to the Supplemental Indenture on the Business Day immediately succeeding the date on which the Trustee shall have received such notice, (vii) may proceed to protect its right by suit in equity, action at law or other appropriate proceedings for specific performance of any covenant or agreement of NCPA contained in the 2008 Series B Reimbursement Agreement or (viii) may exercise any other rights or remedies available under any Related Document, any other agreement or at law or in equity. The rights and remedies of the Bank specified in the 2008 Series B Reimbursement Agreement are for the sole and exclusive benefit, use and protection of the Bank, and the Bank is entitled, but shall have no duty or obligation to NCPA, the Trustee, the Tender Agent, the Bondholders or otherwise, (1) to exercise or to refrain from exercising any right or remedy reserved to the Bank under the 2008 Series B Reimbursement Agreement, or (2) to cause the Trustee or any other party to exercise or to refrain from exercising any right or remedy available to it under any of the Related Documents.

(b) From and after the occurrence of an Event of Default, all amounts owing to the Bank under the 2008 Series B Reimbursement Agreement and amounts owing on any Bank Bonds shall bear interest at the Default Rate.

If any Event of Default shall occur, then and in every such case the Bank shall be entitled to proceed to protect and enforce its rights by such appropriate judicial proceeding as it may deem most effectual to protect and enforce any such right, either by suit, in equity, or by action at law, whether for the specific performance of any covenant or agreement contained in the 2008 Series B Reimbursement Agreement, in aid of the exercise of any power granted in the 2008 Series B Reimbursement Agreement, or to enforce any other legal or equitable right vested in the Bank by the 2008 Series B Reimbursement Agreement, the Bank Bonds, the Related Documents or by law. The provisions of the 2008 Series B Reimbursement Agreement shall be a contract with the Bank and the duties of NCPA shall be enforceable, subject to judicial discretion and the availability of equitable remedies, by the Bank by mandamus or other appropriate suit, action, or proceeding in any court of competent jurisdiction.

Alternate Credit Facility and Liquidity Facility

At any time, NCPA may obtain an alternate Credit Facility and Liquidity Facility (which may be the same instrument) to replace the Letter of Credit then in effect for a Series of 2008 Bonds. The 2008 Bonds of such Series are subject to mandatory tender for purchase in connection with such any such substitution or replacement. See "DESCRIPTION OF THE 2008 BONDS – Purchase of 2008 Bonds – Mandatory Tender for Purchase Upon Substitution, Termination or Expiration of a Letter of Credit."

CERTAIN INFORMATION CONCERNING BANK OF MONTREAL

Bank of Montreal (as previously defined herein, the "Bank") (NYSE, TSX: BMO) is a highly diversified financial services provider, offering a broad range of retail banking, wealth management and investment banking products and services. Canadian clients are served through the Canadian retail arm, BMO Bank of Montreal, and through the wealth management businesses, BMO Nesbitt Burns, BMO InvestorLine, BMO Insurance and BMO Harris Private Banking. BMO Capital Markets, the Bank's North American investment and corporate banking division, provides a full suite of financial products and services to its North American and international clients. In the United States, clients are served through Chicago-based BMO Harris Bank N.A., an integrated financial services organization that provides banking, financing, investing, and cash management services. BMO Financial Group comprises three operating groups: Personal and Commercial Banking (P&C), comprised of P&C Canada and P&C U.S.; Private Client Group (PCG); and BMO Capital Markets.

Bank of Montreal commenced business in Montreal in 1817 and was incorporated in 1821 by an Act of Lower Canada as the first Canadian chartered bank. In 1984, the Bank acquired Chicago's Harris Bankcorp, Inc., a financial services firm with roots stretching back to 1882.

The Bank's annual consolidated financial statements, accompanying management's discussion and analysis, annual information form, quarterly financial statements, interim filings, and certain other financial information relating to the Bank are available on SEDAR (*http://www.sedar.com*), EDGAR (*http://www.sec.gov*) and on the Bank's website (*http://www2.bmo.com/ir*), or will be provided without charge upon written request directed to: Bank of Montreal, Corporate Secretary's Department, 1 First Canadian Place, 21st Floor, Toronto, Ontario M5X 1A1. The financial information referenced in this paragraph is *not* incorporated by reference into this Remarketing Memorandum.

Each of the Series A Letter of Credit and the Series B Letter of Credit will be solely an obligation of the Bank, and will not be an obligation of, or otherwise guaranteed by, any other member of BMO Financial Group, and no assets of BMO Financial Group (other than those of the Bank) or any affiliate of the Bank will be pledged to the payment thereof.

The information above contained under this caption "CERTAIN INFORMATION CONCERNING THE BANK" relates to and has been obtained from the Bank. The delivery of this Remarketing Memorandum shall not create any implication that there has been no change in the affairs of the Bank since the date such information was provided by the Bank, or that the information contained or referred to under this caption is correct as of any time subsequent to the date it was provided by the Bank.

THE REMARKETING AGENT

Citigroup Global Markets Inc. ("Citi") has been appointed to serve as the Remarketing Agent for each Series of the 2008 Bonds pursuant to the Indenture and the Remarketing Agreement. Under the terms of the Indenture, the Remarketing Agent will exercise its best efforts to sell the applicable Series of the 2008 Bonds (including Bank Bonds) issued thereunder on the same date designated for purchase thereof in accordance with the Indenture and, if not remarketed on such date, thereafter until sold, at a price equal to par plus accrued interest, with such interest component of the sales price being determined by the Remarketing Agent, with consent of the Tender Agent, in order to best facilitate remarketing.

OTHER INVESTMENT CONSIDERATIONS

The following information should be considered by prospective investors in evaluating the 2008 Bonds. However, the following does not purport to be an exclusive listing of risks and other considerations that may be relevant to investing in the 2008 Bonds, and the order in which the following information is presented is not intended to reflect the relative importance of any such risks and considerations.

Expiration of the Letters of Credit

The scheduled termination date of each of the Letters of Credit is September 9, 2019, subject to extension or earlier termination in certain circumstances as described therein. If a Letter of Credit is not extended or another Credit Facility and Liquidity Facility is not obtained by NCPA, the 2008 Bonds of the related Series will be subject to mandatory tender for purchase. There can be no assurance that NCPA will be able to obtain an extension of a Letter of Credit or another Credit Facility and Liquidity Facility. The Bank is under no obligation to extend either Letter of Credit beyond the scheduled termination date thereof or to honor any drawing under either Letter of Credit not made in strict conformity with the terms thereof.

Bank's Obligations Unsecured

The ability of the Bank to honor draws upon the Letter of Credit for the related Series of the 2008 Bonds is based solely upon the Bank's general credit and is not collateralized or otherwise guaranteed by the United States of America or any agency or instrumentality thereof. No provision has been made for replacement of or substitution for either of the Letters of Credit in the event of any deterioration in the financial condition of the Bank. Neither NCPA nor the Bank assumes any liability to any purchaser of the 2008 Bonds as a result of any deterioration of the financial condition of the Bank. Upon any insolvency of the Bank, any claim by the Trustee against the Bank would be subject to bank receivership proceedings.

General Factors Affecting the Bank

The Bank is subject to regulation and supervision by various regulatory bodies. New regulations could impose restrictions upon the Bank which would restrict its ability to respond to competitive pressures. Various legislative or regulatory changes could dramatically impact the banking industry as a whole and the Bank specifically. The banking industry is highly competitive in many of the markets in which the Bank operates. Such competition directly impacts the financial performance of the Bank. Any significant increase in such competition could adversely impact the Bank.

Short-Term Ratings Based Solely on Bank Ratings

The short-term ratings on each Series of the 2008 Bonds are based upon the Bank's ratings and assume the issuance of the related Letter of Credit by the Bank. See "RATINGS." It is possible that the Bank's current ratings could be downgraded; lower ratings could affect the liquidity or market price of the 2008 Bonds.

Performance by Trustee

Performance by the Bank of its obligations under each of the Letters of Credit is subject to the satisfaction of specific conditions by the Trustee as set forth in the related Letter of Credit. Holders of the 2008 Bonds of each Series are therefore dependent upon the Trustee acting to satisfy such conditions before they will receive the benefit of the related Letter of Credit. In addition, the question of whether the Trustee has properly satisfied such conditions is a question of fact which, if disputed, could delay or defeat the Trustee's rights of enforcement of the related Letter of Credit.

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, 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, dated September 22, 1993, as such may be amended from time to time, establishes the contractual relationship between NCPA and its Members under which NCPA may acquire, construct, finance and plan for the addition of generation and power supply projects (otherwise referred to as "NCPA Projects"), and to manage, maintain, operate, schedule and perform billing for NCPA Projects. NCPA develops NCPA projects using a multi-step process during which projects are identified, Members elect to subscribe to projects, and all formal and binding commitments are made between NCPA and the subscribing Members for financing, construction, operation and maintenance of NCPA Projects.

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, 2013 and 2012 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.

JAMES POPE, General Manager, was appointed General Manager of NCPA in January 2004. Prior to the appointment Mr. Pope served for eight years as the Director of Electric Utility for the City of Santa Clara. Mr. Pope has experience in the electric and gas industry with a background in general management, operations, engineering and construction for PG&E serving as Vice President, Technical and Construction Services; Vice President for Sacramento Valley Region; and Manager, Gas Transmission and Distribution Construction. During his over 45 years of industry experience, Mr. Pope has been in various public power leadership roles, including positions as Chairman and Vice Chairman of the Transmission Agency of Northern California (TANC) where he started the process to get Path 15 built. Mr. Pope now serves on the Board of Governors of the California Municipal Utilities Association (CMUA), and the Board of Directors of the California Foundation on the Environment and the Economy (CFEE). He also served as a member of the Board of Governors of the California Independent System Operator (CAISO). In March 2002, he was appointed by Secretary of Energy Spencer Abraham to serve on the Secretary's Electricity Advisory Board.

Mr. Pope has a Bachelor of Science degree from Oregon State University and a Masters of Science degree in Civil Engineering from Stanford University. He attended the Harvard University Business School (Program for Management Development) Executive Program.

DONNA STEVENER, Assistant General Manager, Finance/Administrative Services, Chief Financial Officer, received a Bachelor of Science degree in Business Administration/Accounting with high honors from California Baptist University. Ms. Stevener is a retired Certified Public Accountant in the State of California and has over 32 years of finance experience, including over 22 years specializing in the power industry. Before joining NCPA in April 2005, Ms. Stevener was employed by Riverside Public Utilities as a member of the executive management team. At NCPA, Ms. Stevener oversees the Administrative Services division which includes finance, accounting, power settlements, information services and facilities management and performs as the Chief Financial Officer of NCPA.

JANE CIRRINCIONE, Assistant General Manager, Legislative and Regulatory, received a Masters 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 in Santa Clara, California and the London School of Economics. Ms. Cirrincione has over 27 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 2006 recipient of the Robert E. Roundtree Rising Star Award recognizing future leaders of public power systems.

DAVID DOCKHAM, Assistant General Manager, Power Management, has worked in the electric utility industry since 1982 on a broad range of utility industry projects, activities and issues. Mr. Dockham's experience includes contract development and negotiation, engineering design, system planning, policy and procedure development, public presentations to boards, commissions and industry work groups; and participation in regional and state level policy and technical working groups. From 2001 through 2007, Mr. Dockham managed NCPA's activities and interactions with the CAISO and associated regulatory proceedings on behalf of the NCPA's Members utilizing services under the Second Amended and Restated NCPA Metered Subsystem Aggregation Agreement and the NCPA-PG&E Interconnection Agreement. He currently manages planning, contracts, fuel purchases, and pooling arrangements for NCPA. Mr. Dockham has a Bachelor of Science degree in Electrical and Electronic Engineering from California State University, Sacramento, a Masters degree in Business Administration from the University of California, Davis and is a registered Professional Engineer in the State of California.

KEN SPEER, Assistant General Manager, Generation Services, has over 34 years of experience in the generation resource management field, having also managed significant generation facilities for the City of Santa Clara (Silicon Valley Power) and PG&E. Mr. Speer also served as the Director of Capital Investment for Duke Energy North America, where he oversaw the capital investment program for the company's California-based assets. Mr. Speer has a Bachelor of Science degree in Mechanical and Nuclear Engineering from the University of California, Berkeley, and is a Registered Mechanical Engineer.

VICKI CICHOCKI, Human Resources Manager received a Bachelor of Science degree from Ohio Wesleyan University, Delaware, Ohio and a Master's degree from Purdue University in West Lafayette, Indiana. Ms. Cichocki has over 25 years of experience in human resources in a variety of industries, with over 18 of those years in a management role. Ms. Cichocki assumed her duties with NCPA in May 2014. Prior to joining NCPA, she was the Director of Human Resources for California State Employees Association. She also has prior work experience with a multi-national information technology corporation, a vision care benefit provider and a nation-wide cellular company.

NCPA Power Pool

NCPA operates a power pool that includes the following Members: Alameda, Biggs, Gridley, Healdsburg, Lodi, Lompoc, Palo Alto, Plumas Sierra Rural Electric Cooperative, the Port of Oakland and Ukiah (each, an "NCPA Pool Member"). The ten NCPA Pool Members' service areas are connected 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 Second Amended and Restated NCPA Metered Subsystem Aggregation Agreement (the "MSSA") 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 Project output across the CAISO-controlled grid as requested by Roseville. The Central Dispatch Center also monitors and controls load and voltage levels, operates generating facilities, enters into buy and sell transactions with other utilities throughout the western United States and Canada and regulates 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 the market applicable rules established by CAISO and FERC. The MSSA identifies operational terms and conditions that vary from the CAISO tariff, largely allowing NCPA Members to continue to operate as a vertically integrated utility 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 entered into an Interconnection Agreement (the "NCPA-PG&E Interconnection Agreement") that provided for the terms and conditions for connecting NCPA resources and member loads to the CAISO-controlled grid, 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.

In April 2009, the CAISO implemented a complete overhaul of its tariff, replacing the market design embodied under the CAISO tariff with an updated market design and tariff which has been entitled the Market Redesign and Technology Upgrade ("MRTU"). This overhaul largely changes how generation units are scheduled, transmission rights are allocated, and wholesale energy, capacity and ancillary service costs are allocated to NCPA and its Members. NCPA was an active participant in FERC proceedings, CAISO-led stakeholder meetings, and market simulations to test market participant scheduling and settlement systems in advance of MRTU implementation to ensure that Member interests were protected and that NCPA would be able to operate successfully under the new market design. NCPA and the CAISO negotiated amendments to the MSSA to adapt to the changes resulting from MRTU.

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

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. While there have from time to time been bankruptcies among participants in those markets, NCPA claims against those bankruptcy estates have all been resolved and NCPA does not have any additional financial exposure due to past bankruptcies in the electric utility industry.

Investment of NCPA Funds

All funds of NCPA (except bond proceeds which are invested pursuant to the indenture under which such bonds are issued) 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 and monthly activity reports are approved by the NCPA Commission.

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, and (ix) commercial paper.

The Investment Policy provides the following guidelines, among others. All rated securities must be rated by Moody's or S&P as "A" or better. All certificates of deposit must mature within one year. All collateralized certificates of deposit must mature within one year. Certificates of deposit with a face value in excess of $100,000 will be collateralized by Treasury Department securities or first mortgage loans. The Treasury bills or notes must be at least 110% of the face value of the certificate of deposit collateralized in excess of the first $100,000. The value of first mortgages must be at least 150% of the face value of the certificate of deposit balance secured in excess of the first $100,000. 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 and the Local Agency Investment Fund, 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 243-MW Collierville Powerhouse, (c) the Spicer Meadow Dam with a 5.5-MW powerhouse, and (d) associated tunnels located essentially on the North Fork Stanislaus River and on the Stanislaus River in Alpine, Tuolumne and Calaveras Counties, California, together with required transmission and related facilities.

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. Calaveras is a county water district formed under the laws of the State of California. Calaveras' primary objective is to provide water and wastewater service to the residents of Calaveras County. In so doing, Calaveras is engaged in the development of hydroelectric power for financial support and water supplies. Calaveras' operational activities of providing water and wastewater service include approximately 13,000 customers. Calaveras has no obligation on the 2008 Bonds.

Pursuant to the Power Purchase Contract, NCPA (i) is entitled to the electric output 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 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 and available stream flows. The Project has a 100-year record (1913 to 2013) of streamflows. Based upon the record, the Project's average production is estimated to be 554 GWh annually. Using the driest period of record (1976-1977), the Project is estimated to produce 176 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, together with the ability to schedule Western energy deliveries, give 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 Fiscal Year ended June 30, 2013 was approximately 270 GWh, a substantially below average year hydrological year, compared with 463 GWh for the prior Fiscal Year, which was also a below average hydrological year. The net Project generation for the Fiscal Year ending June 30, 2014 was 197 GWh due to the current drought conditions in California.

NCPA financed the Project through the issuance of Hydroelectric Project Number One Revenue Bonds, of which approximately $401.2 million aggregate principal amount was outstanding as of June 30, 2014. 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 capacity of the Project to certain of its Project Participants (described below) pursuant to "take-or-pay" power sales contracts which require payments to be made whether or not the project is completed or operable. Each purchaser is responsible under its 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 shares of 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 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.

NCPA has estimated the average cost per kWh of power generated from the Project to be approximately 7.8 cents/kWh in 2013-14 dollars (based on an average water year), however, due to drought conditions in California and lower than average output, the current average cost per kWh through June 30, 2014 is 21.8 cents/kWh. The average cost per kWh of power generated from the Project over the prior five Fiscal Years is shown in the following table:

Fiscal Year	Average Cost of Power (cents/kWh)[1]
2009-10	6.57
2010-11	4.13
2011-12	8.97
2012-13	16.52
2013-14	21.82

(1) Average Cost of Power has been restated to net out ancillary services revenue.

THE PROJECT PARTICIPANTS

General

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

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 and Ukiah obtain a portion of their power needs from Western. Biggs, Gridley, Palo Alto, Plumas-Sierra and Roseville 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 PG&E and 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, Western transmission facilities, the California-Oregon Transmission Project ("COTP") or combinations of those three transmission facilities.

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 and under the authority of the Rural Electrification Act of 1935.

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 related 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 has constructed a natural gas-fired, combined-cycle power generation plant located in the City of Lodi, San Joaquin County, California (the "Lodi Energy Center"), which was placed into commercial operation on November 27, 2012. The costs of construction of the Lodi Energy Center were approximately $385.7 million. The electric generation components (the "Power Island") of the Lodi Energy Center consist of the following components: (1) one natural gas-fired Siemens STGS-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 plant is designed to be capable of operating at 296 MW (it has been permitted to operate at this level and it has the equipment necessary to operate at this level) but is expected to operate at 280 MW under the terms of the transmission interconnection agreement with the CAISO and PG&E.

The Lodi Energy Center has a designed net heat rate of 6,804 Btu/kWh at 94 degrees F. This heat rate is low in comparison to other natural gas-fired generating facilities, and means that this plant is expected to be very efficient and utilize less natural gas than most gas-fired plants to generate electric energy. Even when gas prices are high, NCPA believes that the Lodi Energy Center will be competitive to other, less-efficient, gas-fired plants in the region.

Pursuant to a 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 (such entities other than NCPA, collectively the "LEC Project Participants"), NCPA agreed to construct and operate the Lodi Energy Center and sold the capacity and energy of the Lodi Energy Center to the thirteen LEC Project Participants, in accordance with their respective generation entitlement shares to the capacity and energy of the Lodi Energy Center. Each LEC Project Participant is responsible for the payment of its respective share of the costs of construction of the Lodi Energy Center. In order to provide funding for a portion of the costs of the Lodi Energy Center, in June 2010, NCPA issued two series of revenue bonds, its $255.0 million Lodi Energy Center Revenue Bonds, Issue One (the "LEC Issue One Bonds"), 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 the California Department of Water Resources) and its $140.8 million Lodi Energy Center Revenue Bonds, Issue Two (the "LEC Issue Two Bonds"), issued on behalf of the California Department of Water Resources. As of June 30, 2014, $245.8 million of LEC Issue One Bonds and $133.0 million of LEC Issue Two Bonds were outstanding. 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 Modesto Irrigation District provided its own financing for its share of the estimated costs of construction of the Lodi Energy Center.

The Lodi Energy Center is being 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.

Generation for Lodi Energy Center for Fiscal Year 2013-14 was 1,242,000 MWh. Cumulative availability since startup is over 90% with a capacity factor of 56.7%. The cost per kWh (before revenues) during the Fiscal Year 2013-14 is 7.3 cents/kWh. The net cost to project participants, after subtracting project revenues, is 2.25 cents/kWh for the same time period.

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), each with two 55 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), each with two 55 MW (nameplate rating) turbine generator units. 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 and Plant 2 are now operated together as the 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, by April 1988, for the purpose of slowing the decline in the steam field capability, NCPA changed its steam field production from base-load to load-following and reduced average annual generation. These changes were effective in reducing the decline in steam production.

Beginning in 1991, along with other steam field operators in the area, NCPA began implementing various operating strategies 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 at higher mass-flow rates to optimize the utilization of the available steam resource.

NCPA also entered into agreements with other producers 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 waste-water from Lake County Sanitation District treatment plants at Clearlake and Middletown and delivers the waste water to NCPA and the other Geysers steam field operator for injection into the steam field. A second pipeline enhancement project to further augment the waste-water injection program was completed in 2004. Contractual changes made in connection with the project have increased NCPA’s entitlement to receive waste-water for reinjection from 33% to 44%.

NCPA financed the Geothermal Project with Geothermal Project Number 3 Revenue Bonds, of which $41.3 million were outstanding as of June 30, 2014. 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. 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.

Average annual generation of the Project was approximately 101.1 MW gross (“MWG”) for calendar year (“CY”) 2013. Based on current operating protocols and forecasted operations, after CY 2013 both the average and peak capacity are expected to increase due to the installation of new turbines in Plant 1, reaching approximately 107.4 MWG in CY 2014 and then decline approximately 2% per year to approximately 67 MWG by CY 2038. 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. 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. These decommissioning costs are currently estimated to total approximately $29.4 million. NCPA has been collecting monies to pay the expected decommissioning costs since 2007 and holds $10.0

million in a reserve for such purpose as of June 30, 2014. Collections towards future decommissioning costs are expected to be approximately $1.9 million for Fiscal Year 2014-15.

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) an ownership 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.

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. NCPA financed the Capital Facilities Project with Capital Facilities Revenue Bonds, of which approximately $48.1 million were outstanding as of June 30, 2014. The Cities of Alameda, Lodi, Lompoc and Roseville are the project participants in the Capital Facilities Project. 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 to meet the project participants' load, depending on the amount of generation available from NCPA's hydroelectric project and prices of alternative electric energy supplies, to meet other NCPA Members' load or to sell power to third parties depending on natural gas prices and electric energy prices.

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 was effective on September 1, 2010.

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 capacity reserve requirements. Such reserve capacity is operated only during emergency periods when other resources are unexpectedly out of service. As is typical of reserve and peaking resources, the average cost per kWh of power delivered to the participants in the Combustion Turbine Project is comparatively expensive.

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. Alameda, Lodi, Roseville and Santa Clara, together with Healdsburg, Lompoc, Ukiah and Plumas-Sierra, are participants in Combustion Turbine Project Number One.

Gas Supply and Purchase Contracts

On behalf of the project participants of Combustion Turbine Project Number One and of the Capital Facilities Project's Unit One, NCPA has executed a Gas Supply and Fuel Management Agreement with EDF Trading North America, LLC (EDFT), effective January 1, 2013 to provide gas supply, scheduling, nomination, balancing and settlement services. for the management of NCPA's gas supply for these projects. In addition, NCPA has executed an Asset Management Agreement ("AMA") for natural gas pipeline capacity with EDFT, effective January 1, 2013 to provide pipeline management. Under the AMA, EDFT manages and provides value for NCPA's gas transportation rights of 2,743 MMBtu/day of pipeline capacity from AECO (Canadian Trading hub - Alberta, Canada) to the PG&E Citygate (northern California). The pipeline capacity rights are 30 year commitments with TransCanada and PG&E ending October 31, 2023. Both agreements with EDFT are automatically renewed each year on January 1, unless terminated by either party with a six-month notice of termination. On June 30, 2014 EDFT provided written notice of its termination of the AMA; therefore the services provided by EDTF under the AMA will end on December 31, 2014. As a result of such notice, NCPA is currently working to identify a replacement pipeline manager to provide pipeline management services effective January 1, 2015.

NCPA and J.P. Morgan Ventures Energy Corporation ("JPMVEC") have executed a contract to provide the gas supply and the nomination, imbalance and settlement services for NCPA's Lodi Energy Center. NCPA has taken services from JPMVEC under such agreement since the Lodi Energy Center began commercial operations on November 27, 2012, and the agreement may be terminated by either party upon a six-month notice of termination.

Power Purchase and Other Contracts

Seattle City Light Exchange Agreement. NCPA, on behalf of Healdsburg, Palo Alto, Ukiah, Lodi and Roseville, has negotiated a seasonal exchange agreement with Seattle City Light for 60 MW of summer capacity and energy and a return of 46 MW of capacity and energy in the winter. Deliveries under the agreement began June 1, 1995. NCPA has provided notice to terminate the agreement to Seattle City Light effective in 2018. Effective May 31, 2008, Healdsburg, Palo Alto and Roseville assigned their participation percentages to Santa Clara.

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.

Gridley PV Renewable Energy Power Purchase Agreement. On December 29, 2010, NCPA entered into a Renewable Energy Power Purchase Agreement with Lightbeam Power Company Gridley Main LLC, on behalf of the City of Gridley, to purchase the output of a 1.0 MW AC solar powered generating facility located in the City of Gridley. The term of the transaction is twenty five (25) years from the date of commercial operation. The facility became commercially operational on March 1, 2014. The generating facility is expected to produce renewable energy to serve City of Gridley load, and satisfy any applicable renewable energy requirements, through February 2039.

Western GeoPower Power Purchase Agreement. NCPA, on behalf of Santa Clara, Roseville, Palo Alto, Lompoc, and Port of Oakland, negotiated an Amended and Restated Renewable Power Purchase Agreement in May 2011 with Western GeoPower Incorporated ("Western Geo"), a wholly owned subsidiary of Ram Power Corp of Reno, Nevada. Due to default of the counterparty, this contract was terminated on May 11, 2013 and NCPA received $1,098 in liquidated damages for delays in the project.

BART PV Renewable Energy Power Purchase Agreement. On November 17, 2011, NCPA entered into a Renewable Energy Power Purchase Agreement with Lightbeam Power Company Gridley Main Two LLC, on behalf of the Bay Area Rapid Transit District (BART), to purchase the output of a 2.5 MW AC solar powered generating facility located in the City of Gridley. The term of the transaction is twenty five (25) years from the date of commercial operation. The facility became commercially operational on April 1, 2014. The generating facility is expected to produce renewable energy to serve BART load, and satisfy any applicable renewable energy requirements, through March 2039.

Nacimiento Renewable Energy Power Purchase Agreement. On April 1, 2014, NCPA entered into a Renewable Energy Power Purchase Agreement with Monterey County Water Resources Agency, on behalf of the Bay Area Rapid Transit District (BART), to purchase the output of a 4.4 MW small hydroelectric generating facility located in Bradley, California. The term of the transaction is approximately twenty (20) years from the effective date of the transaction. The facility began delivery of capacity and energy to NCPA on April 1, 2014. The generating facility is expected to produce renewable energy to serve BART load, and satisfy any applicable renewable energy requirements, through December 31, 2033.

BART Services Agreement. NCPA provides power supply and scheduling services to BART under a ten-year Single Member Services Agreement which was executed on December 1, 2005. Under this agreement, NCPA procures power to meet BART's power supply needs utilizing NCPA Commission-approved Edison Electric Institute and WSPP Inc. Purchase Agreements.

Market Purchase Program. NCPA, on behalf of Alameda, Biggs, Gridley, Healdsburg, Lodi, Lompoc and Ukiah may enter into supply agreements for terms of up to five years utilizing NCPA 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 Market Purchase Program was approved by the NCPA Commission on July 26, 2007, with a term of five years, which is extended for one year on each anniversary of the agreement as to each participant that does not withdraw from the agreement or have their participation terminated.

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 (ii) 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, with an initial term of five years, which is extended for two years on every other anniversary of the agreement as to each participant that does not withdraw from the agreement or have their participation terminated.

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 Federal Power Act, 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 Sections 211, 211A, 212 and 213 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 CHANGES IN CALIFORNIA

Proposition 218

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 XIIID creates additional requirements for the imposition by most local governments (including the Project Participants) 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. Nevertheless, Proposition 218 could indirectly affect some California municipally-owned electric utilities. For example, to the extent Proposition 218 reduces a city's general fund revenues, that city could seek to increase the transfers from the electric utilities of that city to the city's general fund.

Article XIIIC expressly extends the people's initiative power to reduce or repeal previously-authorized local taxes, assessments, and fees and charges. The terms "fees and charges" are not defined in Article XIIIC, although the California Supreme Court held in *Bighorn-Desert View Water Agency v. Verjil*, 39 Cal. 4th 205 (2006), that the initiative power described in Article XIIIC may apply 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 electric rates are subject to the initiative power. Thus, even electric service charges (which are expressly exempted from the provisions of Article XIIID) might be subject to the initiative provision of Article XIIIC, thereby subjecting such fees and charges imposed by each Project Participant to reduction by the electorate. However, NCPA and the Project Participants believe that even if the electric rates of any Project Participants are subject to the initiative power, under Article XIIIC or otherwise, their respective electorates would be precluded from reducing electric rates and charges in a manner adversely affecting the payment of the 2008 Bonds by virtue of the "impairments clause" of the United States Constitution.

Proposition 26

Proposition 26 was approved by the electorate at the November 2, 2010 election and amended California Constitution Articles XIIIA and XIIIC. The proposition imposes a two-thirds voter approval requirement for the imposition of fees and charges by the State. It also imposes a majority voter approval requirement on local governments with respect to fees and charges for general purposes, and a two-thirds voter approval requirement with respect to fees and charges for special purposes. Proposition 26, according to its supporters, is intended to prevent the circumvention of tax limitations imposed by the voters pursuant to Proposition 13, approved in 1978, and other measures through the use of non-tax fees and charges. Proposition 26 expressly excludes from its scope 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 cost to the State or local government of providing the service or product to the payor. Proposition 26 may, however, be interpreted to limit fees and charges for electric utility services charged by governmental entities such as the Project Participants to preclude future transfers of electric utility generated funds to a local government's general fund, if applicable, and/or to require stricter standards for the allocation of costs among customer classes. A lawsuit was filed against NCPA member, the City of Redding ("Redding"), in the Superior Court in Shasta County alleging that Redding's transfers of funds from its electric utility to its city general fund violated Proposition 26 (*Citizens for Fair REU Rates et al. v. City of Redding, et al.* Shasta Superior Court no. 171377.) The case was tried on November 8, 2011 and on December 22, 2011, the Court determined that the local legislation authorizing the transfer predated Proposition 26 and since Proposition 26 did not apply retroactively, the transfer was unaffected by Proposition 26. Following the filing of first lawsuit, the Plaintiffs initiated a related lawsuit challenging the resolution adopting Redding's biennial City Budget for fiscal years 2012 and 2013 and raising similar issues (*Fee Fighter LLC et al. v. City of Redding, et al*. Shasta Superior Court no. 172960.) Redding similarly prevailed in the trial court on the second case on the grounds that Redding's transfer obligations were grandfathered under Proposition 26, because the transfer requirement pre-dated Proposition 26's effective date, even though the transfer was a component of an electric rate adopted after Proposition 26 became effective. These two cases were consolidated on appeal with the Third District Court of Appeal (Case Number C071906), and have been fully briefed. A decision is expected in 2014. NCPA and the Project Participants are unable to predict at this time how Proposition 26 will be interpreted by other courts or what its ultimate impact will be.

Other Initiatives

Articles XIIIC and XIIID were adopted as measures that qualified for the ballot pursuant to California's initiative process. From time to time, other initiatives have been, and could be, proposed, and if qualified for the ballot, could be enacted affecting 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.

DEVELOPMENTS IN THE CALIFORNIA ENERGY MARKETS

State Legislation

A number of bills affecting the electric utility industry have been introduced or enacted by the California Legislature in recent years. In general, these bills regulate greenhouse gas emissions and provide for greater investment in energy-efficiency and environmentally friendly generation alternatives through more stringent renewable resource portfolio standards. The following is a brief summary of certain of these bills that have been enacted.

Greenhouse Gas Emissions – Executive Orders. On June 1, 2005, then Governor Arnold Schwarzenegger signed Executive Order S-3-05, which placed an emphasis on efforts to reduce greenhouse gas emissions by establishing statewide greenhouse gas reduction targets. The targets are: (i) a reduction to 2000 emissions levels by 2010; (ii) a reduction to 1990 levels by 2020; and (iii) a reduction to 80% below 1990 levels by 2050. The Executive Order also called for the California Environmental Protection Agency to lead a multi-agency effort to examine the impacts of climate change on California and develop strategies and mitigation plans to achieve the targets. On April 25, 2006, then Governor Schwarzenegger also signed Executive Order S-06-06 which directs the State of California to meet a 20% biomass utilization target within the renewable generation targets of 2010 and 2020 for the contribution to greenhouse gas emission reduction.

Greenhouse Gas Emissions – Global Warming Solutions Act. Then Governor Schwarzenegger signed Assembly Bill 32, the Global Warming Solutions Act of 2006 (the "GWSA"), which became effective as law on January 1, 2007. The GWSA prescribed a statewide cap on global warming pollution with a goal of returning to 1990 greenhouse gas emission levels by 2020. In addition, the GWSA established an annual mandatory reporting requirement for all IOUs, local, publicly-owned electric utilities ("POUs"), and other load-serving entities (electric utilities providing energy to end-use customers) to inventory and report greenhouse gas emissions to the California Air Resources Board ("CARB"), required CARB to adopt regulations for significant greenhouse gas emission sources (allowing CARB to design a "cap-and-trade" system) and gave CARB the authority to enforce such regulations beginning in 2012.

On December 11, 2008, CARB adopted a "scoping plan" to reduce greenhouse gas emissions. The scoping plan set out a mixed approach of market structures, regulation, fees and voluntary measures. The scoping plan included a cap-and-trade program. In August 2011, CARB revised the scoping plan in response to litigation. The revised scoping plan continues to include a cap-and-trade program. The scoping plan is required to be updated every five years. In October 2013, CARB released a draft of its 2013 scoping plan update. Public comments on the draft scoping plan update were submitted by November 1, 2013. CARB issued the proposed first update to the scoping plan on February 10, 2014, which was approved by CARB on May 22, 2014. The scoping plan update recommends that a plan to extend the cap-and-trade program beyond 2020 be developed by 2017.

On October 20, 2011, CARB adopted a regulation implementing a cap-and-trade program. The California Office of Administrative Law ("OAL") approved the regulation on December 13, 2011. The cap-and-trade regulation became effective on January 1, 2012. Emission compliance obligations under the regulation began on January 1, 2013. The cap-and-trade program covers sources accounting for 85% of California's greenhouse gas emissions, the largest program of its type in the United States.

The cap-and-trade program is being implemented in phases. The first phase of the program (January 1, 2013 to December 31, 2014) introduces a hard emissions cap that covers emissions from electricity generators, electricity importers and large industrial sources emitting more than 25,000 metric tons of carbon dioxide-equivalent greenhouse gases ("CDE") per year. In 2015, the program will be expanded to cover emissions from transportation fuels, natural gas, propane and other fossil fuels. The cap will decline each year until the end of the program (which is currently set as December 2020 but, as described above, is contemplated by the first scoping plan update to be extended).

The cap-and-trade program includes the distribution of carbon allowances equal to the annual emissions cap. Each allowance is equal to one metric ton of CDE. As part of a transition process, initially, most of the allowances are distributed for free. Additional allowances are being auctioned quarterly (auctions began in November 2012). Utilities can acquire more allowances at these auctions or on the secondary market. IOUs are required to auction the allowances they received for free from CARB. This requirement also applies to POUs that sell electricity into the CAISO markets, other than sales of electricity from resources funded by municipal tax-exempt debt where the POU makes a matched purchase to serve its traditional retail customers. Utilities required to sell their allowances in the auctions are then required to purchase allowances to meet their compliance obligations, and use any remaining proceeds from the sale of their allocated allowances for the benefit of their ratepayers and to meet the goals of the GWSA. POUs that do not sell into the CAISO markets, and those that sell into the CAISO markets only electricity from resources funded by municipal tax-exempt debt, have three options (which are not mutually exclusive) once their allocated allowances are distributed to them. They can (i) place allowances in their compliance accounts to meet compliance obligations for plants they operate directly, (ii) place allowances in the compliance account of a joint powers agency or public power utility that generates power on their behalf, and/or (iii) auction the allowances and use the proceeds to benefit their ratepayers and meet the goals of the GWSA.

The cap-and-trade program also allows covered entities to use offset credits for compliance (not exceeding 8% of a covered entity's compliance obligation). Offsets can be generated by emission reduction projects in sectors that are not regulated under the cap-and-trade program. CARB has approved the following types of offset projects: urban forest projects, reforestation projects, destruction of ozone-depleting substances, livestock methane management projects and destruction of fugitive coal mine methane. CARB is considering additional offset protocols, including protocols for emission reductions through changes to rice cultivation practices (which may be approved in late 2014).

On April 25, 2014, CARB adopted various amendments to the cap-and-trade program, including provisions relating to the electricity sector such as "safe harbor" provisions under the "resource shuffling" prohibition. These amendments became effective on July 1, 2014.

The California cap-and-trade program is linked to the equivalent program in Quebec, Canada. The link took effect on January 1, 2014. California's program may be linked to additional Canadian provincial cap-and-trade programs, and possibly other U.S. state cap-and-trade programs, in later years as part of the Western Climate Initiative. The Western Climate Initiative is a regional effort consisting of California and four Canadian provinces (Quebec, British Columbia, Ontario and Manitoba), which have established a greenhouse gas reduction trading framework.

NCPA and the Project Participants are unable to predict at this time the full impact of the cap-and-trade program on the respective Project Participants' electric utility over the long-term or on the electric utility industry generally or whether any changes to the adopted cap-and-trade program will be made. However, the Project Participants could be adversely affected if the greenhouse gas emissions of their respective resource portfolios are in excess of the allowances administratively allocated to them and they are required to purchase compliance instruments on the market to cover their emissions.

Greenhouse Gas Emissions – Emissions Performance Standard. Senate Bill 1368 ("SB 1368") became effective as law on January 1, 2007. It provides for an emission performance standard ("EPS") restricting new investments in baseload fossil fuel electric generating resources that exceed the rate of greenhouse gas emissions for existing combined-cycle natural gas baseload generation. SB 1368 allows the CEC to establish a regulatory framework to enforce the EPS for POUs such as the Project Participants. The CPUC has a similar responsibility for the IOUs. The regulations promulgated by the CEC were approved by the Office of Administrative Law on October 16, 2007. The CEC regulations prohibit any investment in baseload generation that does not meet the EPS of 1,100 pounds of carbon dioxide ("CO_2") per MWh of electricity produced, with limited exceptions for routine maintenance, requirements of pre-existing contractual commitments, or threat of significant financial harm. In December 2011, the CEC decided to undertake a review of these regulations to ensure there is adequate review of investments in facilities that do not meet the EPS.

On April 5, 2013, the CEC issued its Proposed Final Conclusions in the EPS proceeding. The CEC proposes to expand the public notice requirement so that a POU would have to post a notice of a public meeting at which its governing board would consider any expenditure over $2.5 million to meet environmental regulatory requirements at a non-EPS compliant baseload facility. The CEC further proposes to require each POU to file an annual notice identifying all investments over $2.5 million that it anticipates making during the subsequent 12 months on non-EPS compliant baseload facilities to comply with environmental regulatory requirements. This requirement would be waived for any POU that has entered into a binding agreement to divest within five years of all baseload facilities exceeding the EPS. The CEC does not propose to lower the EPS at this time.

These changes and any future changes to the EPS regulations may impact the Project Participants.

Assembly Bill 1925, signed by then Governor Schwarzenegger on September 26, 2006, additionally requires the CEC to develop a cost-effective strategy for the geologic sequestration and management of industrial CO_2.

Energy Procurement and Efficiency Reporting. Senate Bill 1037 ("SB 1037") was signed by then Governor Schwarzenegger on September 29, 2005. It 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. Each of the Project Participants has complied with such reporting requirements.

Further, California Assembly Bill 2021 ("AB 2021"), signed by then Governor Schwarzenegger on September 29, 2006, requires that the POUs establish, report, and explain the basis of the annual energy efficiency and demand reduction targets by June 1, 2007 and every three years thereafter for a ten-year horizon. A subsequent bill has changed the time interval for establishing annual targets to every four years. Each of the Project Participants has complied with this reporting requirement under AB 2021. Future reporting requirements under AB 2021 include (i) the identification of sources of funding for the investment in energy efficiency and demand reduction programs; (ii) the methodologies and input assumptions used to determine cost-effectiveness; and (iii) the results of an independent evaluation to measure and verify energy efficiency savings and demand reduction program impacts. The information obtained from the POUs is being used by the CEC to evaluate the progress made by the POUs towards the State of California's goal of reducing electrical consumption by 10% within ten years and the greenhouse gas targets presented in Executive Order S-3-05. In addition, the CEC will provide recommendations for improvement to assist each POU in achieving cost-effective, reliable, and feasible savings in conjunction with the established targets for reduction.

Renewable Portfolio Standards. Senate Bill X1 2 ("SBX1 2"), the "California Renewable Energy Resources Act," was signed into law by Governor Jerry Brown on April 12, 2011. SBX1 2 codifies the Renewable Portfolio Standard ("RPS") target for retail electricity sellers to serve 33% of their loads with eligible renewable energy resources by 2020 as provided in Executive Order S-14-08 (signed by Governor Jerry Brown in November 2008). As enacted, SBX1 2 makes the requirements of the RPS program applicable to POUs (rather than just prescribing that POUs meet the intent of the legislation as under previous statutes). However, the governing boards of POUs are responsible for implementing the requirements, rather than the CPUC, as is the case for the IOUs. In addition, certain enforcement authority with respect to POUs is given to the CEC and CARB, including authority to impose penalties.

SBX1 2 requires each POU to adopt and implement a renewable energy resource procurement plan. As set out in more detail in the CEC's RPS enforcement regulation, noted below, the plan must require the utility to procure at least the following amounts of electricity products from eligible renewable energy resources, which may include renewable energy certificates ("RECs"), as a proportion of total kilowatt hours sold to the utility's retail end-use customers: (i) over the 2011-2013 compliance period, an average of 20% of retail sales from January 1, 2011 to December 31, 2013, inclusive; (ii) over the 2014-2016 compliance period, a total equal to 20% of 2014 retail sales, 20% of 2015 retail sales, and 25% of 2016 retail sales; (iii) over the 2017-2020 compliance period, 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; and (iv) for 2021 and each subsequent year, 33% of retail sales for the applicable year.

SBX1 2 grandfathers any facility approved by the governing board of a POU prior to June 1, 2010 as satisfying renewable energy procurement obligations adopted under prior law if the facility is a "renewable electrical generation facility" as defined in the bill (subject to certain restrictions). Renewable electrical generation facilities include certain out-of-state renewable energy generation facilities if such facility: (i) will not cause or contribute to any violation of a California environmental quality standard or requirement, (ii) participates in the accounting system to verify compliance with the RPS program requirements, and (iii) either (a) commenced initial commercial operation after January 1, 2005 or (b) either (x) the electricity generated by the facility is from incremental generation resulting from expansion or repowering of the facility or (y) the electricity generated by the facility was procured by a retail seller or POU as of January 1, 2010. The percentage of a retail electricity seller's RPS requirements that may be met with unbundled RECs from generating facilities outside California declines over time, beginning at 25% through 2013 and declining to a level of 10% in 2017 and beyond.

The CEC has developed detailed rules to implement SBX1 2. On June 12, 2013, the CEC adopted regulations for the enforcement of the RPS program requirements for POUs. In connection with the implementation of SBX1 2, the CEC is responsible for certifying electric generation facilities as "eligible renewable energy resources" for purposes of the RPS program and has adopted guidelines that identify the requirements, conditions and process for certification of facilities as eligible renewable energy resources. The current guidelines identify bio-methane as an eligible renewable energy resource in certain circumstances. Under these guidelines, adopted on April 30, 2013, utilities that procure bio-methane were required to reapply for certification of the generating facilities that use the bio-methane.

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" for information regarding the renewable resources of the Significant Share Project Participants and their progress towards meeting established RPS targets.

Solar Power. On August 21, 2006, then Governor Schwarzenegger signed into law California Senate Bill 1 (also known as the "California Solar Initiative"). This legislation requires POUs, including the Project Participants, to establish a program supporting the stated goal of the legislation to install 3,000 MW of photovoltaic energy in California. POUs are also required to establish eligibility criteria in collaboration with the CEC for the funding of solar energy systems receiving ratepayer-funded incentives. The legislation gives a POU the choice of selecting an incentive based on the installed capacity or based on the energy produced by the solar energy system, measured in kilowatt-hours. Incentives would be required to decrease at a minimum average rate of 7% per year. POUs also have to meet certain reporting requirements regarding the installed capacity, number of installed systems, number of applicants, amount of awarded incentives and the contribution toward the program's goals.

Each of the Project Participants is meeting the requirements of the California Solar Initiative through incentive programs that meet the incentive level for the technology as stipulated under the legislation.

Future Regulation

The electric industry is subject to continuing legislative and administrative reform. States routinely consider changes to the way in which they regulate the electric industry. Historically, both further deregulation and forms of additional regulation have been proposed for the industry, which has been highly regulated throughout its history. While there is no current proposal to further deregulate the industry, there still are additional regulations or legislative mandates being proposed or considered for the industry such as higher reliance on renewable energy and tighter regulations for greenhouse gas emission reductions. NCPA and the Project Participants are unable to predict at this time the impact any such proposals will have on the operations and finances of the Project Participants, the Project or the electric utility industry generally.

Impact of State Developments on NCPA and the Project Participants

The effect of the developments in the California energy markets described above on NCPA and 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 peak demands, the availability and cost of renewable energy, the impact of greenhouse gas emission legislation and regulations, fuel costs and availability, weather effects on customer demand, transmission congestion, the strength of the economy in California and surrounding states and levels of hydroelectric generation within the region (including the Pacific Northwest). See "OTHER FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY." This price volatility may contribute to greater volatility in the Project Participants' costs and revenues of their respective electric systems from the sale (and purchase) of electric energy and, therefore, could materially affect each of the Project Participants' financial condition. Each of the Project Participants, individually and/or through NCPA or other joint powers agencies in which it participates, 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."

OTHER FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY

Federal Energy Legislation

Federal Power Act. Although NCPA and its members are exempt from most federal rate regulation pursuant to Section 201(f) of the Federal Power Act (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.

EPAct 2005 also required the creation of an electric reliability organization ("ERO") to establish and enforce, under FERC supervision, mandatory reliability standards (the "Reliability Standards") to increase system reliability and minimize blackouts. Failure to comply with such mandatory Reliability Standards exposes a utility to significant fines and penalties by the ERO.

On February 3, 2006, FERC issued Order 672, which certified the North American Electric Reliability Corporation ("NERC") as the ERO. Many Reliability Standards have since been approved by FERC.

The ERO or the entities to which NERC has delegated enforcement authority through an agreement approved by FERC ("Regional Entities"), such as the Western Renewable Energy Generation Information System, may enforce the Reliability Standards, subject to FERC oversight, or FERC may independently enforce Reliability Standards. FERC Order 693 further provided the ERO and Regional Entities with the discretion necessary to assess penalties for such violations, while also having discretion to calculate a penalty without collecting the penalty if circumstances warrant.

While the penalties for violations of any of these statutes 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.

Other Federal Legislation. Congress has considered and is considering numerous bills addressing United States energy policies and various environmental matters, including bills relating to energy supplies (such as a federal clean energy portfolio standard), global warming, cybersecurity and water quality. Many of these bills, if enacted into law, could have a material impact on the Project Participants' electric systems and the electric utility industry generally. The impact that federal clean energy portfolio standard legislation would have on the electric utility industry and business generally, and on the Project Participant's electric systems in particular, depends largely on the specific provisions of the legislation that ultimately become law. Some of the important factors to be addressed in any federal clean energy legislation include the clean energy targets and timelines, the list of fuel types accepted as "clean energy," and whether or not existing clean energy sources can be used to meet the targets. The likelihood, timeline and impact of any such legislation cannot be accurately assessed at this time, but it is expected that any such federal action will have a significant impact on fossil-fueled generation facilities. In light of the variety of issues affecting the utility sector, federal energy legislation in other areas such as reliability, transmission planning and cost allocation, operation of markets, environmental requirements and cybersecurity is also possible. However, NCPA and the Project Participants are unable to predict the outcome or potential impacts of any possible legislation at his time.

CAISO Markets

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, evolving reliability requirements and the potential for some types of electricity and gas transactions to be regulated by the Commodity Futures Trading Commission ("CFTC"). CAISO Tariff changes related to these and other issues are currently under discussion in CAISO stakeholder processes and in ongoing FERC proceedings and CFTC rulemaking 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 proposals may have significant impacts on NCPA, the Project Participants or electric utilities generally:

Increased Granularity of LMP. FERC has ordered the CAISO to increase the granularity of its locational marginal pricing ("LMP") framework. Although the CAISO has received permission from FERC to delay the timeline for this change until the second quarter of 2015, increased granularity has the potential to increase cost differentials among NCPA members (including the Project Participants) and between NCPA members and others. However, no concrete proposal has yet been put forward.

Increased Integration of Renewables. As part of the effort to integrate increased levels of intermittent renewable resources into the grid, the CAISO has proposed an array of changes to its existing market structure which could increase costs to NCPA and its members. Effective May 1, 2014, CAISO has implemented a new 15-minute scheduling and settlement market as part of the real-time market process. The new 15-minute market is designed to mitigate real-time market price volatility and improve the ability of intermittent resources to schedule closer to the actual delivery period, but due to limited data there is a risk that the new 15-minute market may cause additional costs uplifts or other anomalies that could have negative implications on the efficiency of the markets.

Centralized Capacity Market. Although the CAISO has committed not to file at FERC for a centralized capacity market in California for the time being, some market participants continue to advocate the adoption of such a market. Centralized capacity markets in other parts of the country have shown potential for significant impacts on the costs of load serving entities ("LSE") and have raised issues about implications for the traditional utility model. However, at present, there is no concrete proposed plan. NCPA will continue to monitor the situation.

Resource Adequacy Requirements. Resource Adequacy requirements apply to NCPA and its members, including the Project Participants. For example, to the extent that a 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. The CAISO has recently filed at FERC for approval of a proposal to add flexible capacity requirements to the existing Resource Adequacy Program. While NCPA will continue to monitor new developments in the CAISO stakeholder process and the proceeding unfolding at the FERC, NCPA is well-positioned to adapt to new requirements in a cost-effective manner.

Environmental Issues

General. 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 NCPA or Project Participant facility or project 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 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. NCPA and the Project Participants cannot predict at this time whether any additional legislation or rules will be enacted that will affect their operations, and if such laws and rules are enacted, what the cost to any of them might be in the future because of such actions.

Greenhouse Gas Regulations Under the Clean Air Act. The United States Environmental Protection Agency (the "EPA") has taken steps to regulate greenhouse gas emissions under existing law. In 2009, the EPA issued a final "endangerment finding," in which it declared that the weight of scientific evidence requires a finding that six identified greenhouse gases, namely, carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride, cause global warming, and that global warming endangers the public health and welfare. The final rule for the "endangerment finding" was published in the Federal Register on December 15, 2009. As a result of this finding, the EPA considered it was authorized to issue regulations limiting CO_2 from, among other things, motor vehicles and stationary sources, such as electric generating facilities, under the federal Clean Air Act. The EPA subsequently issued the "Tailoring Rule," published in the Federal Register on June 3, 2010, which states that greenhouse gas emissions will be regulated from large stationary sources, including electric generating facilities, if the sources emit more than the specified threshold levels of tons per year of CO_2. Large sources with the potential to emit in excess of the applicable threshold will be subject to the major source permitting requirements under the Clean Air Act, including the EPA's Prevention of Significant Deterioration ("PSD") permit program and its Title V operating permit program. Permits would be required in order to construct, modify and operate facilities exceeding the emissions threshold. Examples of such permitting requirements include, but are not limited to, the application of Best Available Control Technology (known as BACT) for greenhouse gas emissions, and monitoring, reporting, and recordkeeping for greenhouse gases.

The endangerment finding and the Tailoring Rule have been challenged in court, but were upheld on June 26, 2012 in a decision by the U.S. Court of Appeals for the District of Columbia Circuit in *Coalition for Responsible Regulation, Inc., et al. v. EPA*. A petition for rehearing was denied on December 20, 2012. In October 2013, several petitions for review relating to these findings were consolidated in the United States Supreme Court case *Utility Air Regulatory Group v. EPA*, dealing with the issue of whether the EPA permissibly determined that its regulation of greenhouse gas emissions from new motor vehicles triggered permitting requirements under the Clean Air Act for stationary sources that emit greenhouse gases. A decision in the case was rendered on June 23, 2014 as described below. Legislation has also been introduced in the United States Congress that would appeal the EPA's endangerment finding or otherwise prevent the EPA from regulating greenhouse gases as air pollutants.

In December 2010, the EPA announced two settlements with a number of states and environmental groups. Pursuant to one settlement agreement dated December 23, 2010, the EPA on April 13, 2012 proposed establishing New Source Performance Standards limiting CO_2 emissions from fossil-fuel fired electric generating units. In response to a June 25, 2013 Presidential memorandum (the "Presidential Memorandum"), the EPA proposed revised, generally more stringent standards on September 20, 2013 and simultaneously rescinded the April 13, 2012 proposal. The new proposed rule was published in the Federal Register on January 8, 2014. The EPA states that the revised standards would apply only to new facilities, not reconstructed or modified facilities. The Presidential Memorandum required the EPA to propose by June 1, 2014, and to finalize by June 1, 2015, standards, regulations, or guidelines that address carbon pollution from modified, reconstructed and existing power plants.

The proposed rule for new power plants would restrict CO_2 emissions from new natural gas-fired units to 1,000 pounds of CO_2 per MWh for larger units and 1,100 pounds of CO_2 per MWh for smaller units. These emission limits are based on the use of natural gas combined cycle technology. CO_2 emissions from new coal-fired units would be restricted to 1,100 pounds of CO_2 per MWh over 12 months, or 1,000-1,050 pounds over seven years. The EPA states that this emission limit reflects the use of partial carbon capture and sequestration as the best system of emission reduction that has been adequately demonstrated for coal-fired units. The basis for this assertion is being challenged in a lawsuit filed by the State of Nebraska in January 2014 in the U.S. District Court for Nebraska. The new performance standard would be the most stringent in the country (surpassing the emission performance standard of 1,100 pounds of CO_2 per MWh of electricity produced imposed by the CEC regulations in California as described under "DEVELOPMENTS IN THE CALIFORNIA ENERGY MARKETS – State Legislation – *Greenhouse Gas Emissions – Emissions Performance Standard*"). The rule is to be finalized in 2015, after which it is likely to be subject to further legal challenges.

On June 2, 2014, the EPA released its "Clean Power Plan" proposal for existing power plants as contemplated by the Presidential Memorandum. The proposed rule is designed to reduce CO_2 emissions from the power sector by as much as 30% nationwide by 2030, as compared to 2005 levels. Under the proposal, the EPA will set different emissions targets for each state based on overall CO_2 emissions and the amount of electricity generated in the state. The proposed emissions target for California for 2030 is expected to be 537 pounds of CO_2 per MWh, representing a reduction of approximately 23.1% from estimated 2012 emissions levels of 698 pounds of CO_2 per MWh. States will have one year after finalization of the rule (until June 2016 under the current schedule) to design their own implementation plans to reach the emissions target. In order to realize the stated level of emissions reductions, the proposed rule includes interim and final emission reduction targets for each individual state. Interim standards would apply from 2020 to 2029, with final standards taking effect in 2030. Emission targets will be able to be met in several ways, including through plant upgrades, switching from coal to natural gas, by improving energy efficiency or promoting renewable energy outside the existing power plant site, or by participating in a cap-and-trade program. In the event a state fails to develop a satisfactory implementation plan, the EPA may impose a federal implementation plan instead.

Concurrently with the release of the Clean Power Plan proposal, the EPA also released a proposal applying specifically to existing power plants subject to modification (which includes a physical or operational change that increases the source's maximum achievable hourly rate of emissions) or reconstruction (which includes the replacement of components of an existing facility to the extent that (i) the fixed capital costs of the new components exceeds 50% of the fixed capital costs that would be required to construct a comparable entirely new facility, and (ii) it is technologically and economically feasible to meet the applicable standards). Under the proposal, reconstructed coal-fired electricity generating units with a heat input of greater than 2,000 MMBtu/h would be required to meet an emissions limit of 1,900 pounds of CO_2 per MWh. Smaller coal-fired units would be required to meet an emission limit of 2,100 pounds of CO_2 per MWh. These emission limits are based on the use of the most efficient generating technology at the affected source. As contemplated in the proposal, modified coal-fired electricity generating units would be required to meet a unit-specific emission limit that is 2% lower than the unit's best historical annual CO_2 emissions rate since 2002 (but not lower than the proposed standards for reconstructed power plants). These standards of performance are based on a combination of best operating practices and equipment upgrades. For modified and reconstructed natural gas-fired power plants, the EPA has proposed the same emissions limits as it did for new facilities. Under the EPA's proposal, facilities with a heat input of greater than 850 MMBtu/h would be required to meet an emission list of 1,000 pounds of CO_2 per MWh. Smaller facilities would be required to meet an emissions limit of 1,100 pounds of CO_2 per MWh.

Comments on the proposed rules for existing and modified and reconstructed power plants will be accepted for 120 days after publication of the proposed rules in the Federal Register (which publication occurred on June 18, 2014). The EPA has indicated that it also intends to hold four public hearings on these proposals in specified cities. Following receipt of input during the public comment period and hearings, the EPA is expected to finalize the rules by June 1, 2015, following the schedule set forth in the Presidential Memorandum.

A petition for extraordinary writ has been filed by Murray Energy Corp. in the U.S. Court of Appeals for the D. C. Circuit seeking to prevent the EPA from moving forward to implement the proposed Clean Power Plan. Additional legal and legislative challenges are also expected.

On June 23, 2014, the United States Supreme Court issued its decision in the *Utility Air Regulatory Group v. EPA* case noted above. In the decision, the Court invalidated substantial portions of the Tailoring Rule, which purported to modify the emissions thresholds set forth in the Clean Air Act (governing when PSD and Title V permitting would be triggered) to account for greenhouse gases, while preserving various aspects of the EPA's ability to regulate greenhouse gas emissions from most new major sources. The decision holds that, for facilities that are otherwise subject to PSD permitting obligations (by virtue of their emissions of conventional pollutants), the EPA may regulate greenhouse gases from those facilities through the PSD BACT standards (without approving the EPA's current approach to BACT regulation of greenhouse gases, or of any approach that may be adopted).

NCPA and the Project Participants are unable to predict the impact of the Court's decision in *Utility Air Regulatory Group v. EPA,* the outcome of any ongoing legal or legislative challenges to other EPA rulemaking with respect to greenhouse gas emissions or the effect that any future final rules promulgated by the EPA regulating greenhouse gas emissions from electric generating units will have on any NCPA project or any of the projects of the Project Participants or their respective electric systems.

Air Quality – National Ambient Air Quality Standards. The Clean Air Act requires that the EPA establish National Ambient Air Quality Standards ("NAAQS") for certain air pollutants. When a NAAQS has been established, each state must identify areas in its state that do not meet the EPA standard (known as "non-attainment areas") and develop regulatory measures in its state implementation plan to reduce or control the emissions of that air pollutant in order to meet the applicable standard and become an "attainment area." The EPA periodically reviews the NAAQS for various air pollutants and has in recent years increased, or proposed to increase, the stringency of the NAAQS for certain air pollutants. The EPA revised the NAAQS for particulate matter on December 14, 2012, the NAAQS for sulfur dioxide on June 22, 2010, and the NAAQS for nitrogen dioxide on February 9, 2010, and in each case made the NAAQS more stringent. It is possible that some areas will be designated as non-attainment based on the revised standards for particulate matter, nitrogen dioxide and sulfur dioxide. These developments may result in stringent permitting processes for new sources of emissions and additional state restrictions on existing sources of emissions, such as power plants. On September 2, 2011, President Obama directed the EPA to withdraw a proposal advanced by it to lower the NAAQS for ozone. As a result of this withdrawal, the EPA resumed the process of issuing non-attainment designations for the ozone NAAQS under the standard set in 2008. On April 30, 2012, the EPA issued ozone non-attainment designations for areas in California, including the Los Angeles – San Bernardino Counties and the Los Angeles – South Coast Air Basin. Additional non-attainment areas for ozone have been and may continue to be designated. On May 29, 2013, the EPA proposed a rule to implement the 2008 ozone NAAQS. Comments on the proposed rule were due to the EPA by August 5, 2013. While implementing the 2008 ozone NAAQS, the EPA is continuing its review of this standard. In January 2014, the EPA released draft risk and exposure assessment documents and a draft policy assessment document relating to this review; comments were due by March 24, 2014. In addition, the Supreme Court recently found in its review of *EPA v. EME Homer City Generation, LP* that the EPA has authority to impose a Cross-State Air Pollution Rule (the "Transport Rule") which curbs air pollution emitted in upwind states to facilitate downwind attainment of three NAAQS.

Mercury and Air Toxics Standards ("MATS"). On December 16, 2011, the EPA signed a rule establishing new standards to reduce air pollution from coal- and oil-fired power plants under sections 111 (new source performance standards, or "NSPS") and 112 (toxics program) of the Clean Air Act. The final rule was published in the Federal Register on February 16, 2012. The EPA updated the MATS emission limits on November 30, 2012 and again on March 28, 2013. The EPA is currently reconsidering certain aspects of the regulation. Under section 111 of the Clean Air Act, MATS revises the standards that new and modified facilities, including coal- and oil-fired power plants, must meet for particulate matter, sulfur dioxide, and nitrogen oxides. Under section 112, MATS sets new toxics standards limiting emissions of heavy metals, including mercury, arsenic, chromium, and nickel; and acid gases, including hydrochloric acid and hydrofluoric acid, from existing and new power plants larger than 25 MW that burn coal or oil. Power plants have up to four years to meet these standards. While many plants already meet some or all of these new standards, some plants will be required to install new equipment to meet the standards.

Regulation of Coal Combustion Residuals. On June 21, 2010, the EPA proposed to regulate coal combustion residuals such as ash. The EPA proposed to list these residuals as a special waste and regulate them as a hazardous waste. This would require a federal or state permitting program covering the storage, treatment, transport, disposal, and other activities related to residuals. The EPA also proposed an alternative regulation that would classify residuals as nonhazardous solid waste. Under the alternative regulation, plants could dispose of residuals in surface impoundments or landfills if they comply with national minimum standards. The disposal standards would address location, liner requirements, groundwater monitoring and other issues, but permits would not be required under the alternative regulation. The EPA solicited additional public comments on its proposed coal combustion residual regulation on October 12, 2011 and again on August 2, 2013. The EPA is under a court-ordered deadline to complete the CCR rulemaking by December 19, 2014.

Effluent Limitations Guidelines and Standards. On June 7, 2013, the EPA proposed to set technology-based effluent limitations guidelines and standards for metals and other pollutants in wastewater discharged from steam electric power plants. The proposal would cover wastewater associated with several types of equipment and processes, including flue gas desulfurization, fly ash, bottom ash, flue gas mercury control and gasification of fuels. The EPA is also considering best management practices for surface impoundments containing coal combustion residuals. The EPA proposed four preferred alternatives for regulating wastewater discharges. The stringency of controls, types of waste streams covered, and the costs vary between the four alternatives. The public comment period on this proposal ended on September 20, 2013. The EPA was expected to issue a final rule in May 2014 but in December 2013 it announced that it would need additional time to finalize this rule.

Santa Clara, one of the Significant Share Project Participants, purchases power from a coal-fired power station that may be affected by these rules, and therefore may be exposed to increased costs in connection with those purchases.

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 affect the financial condition and competitiveness of many electric utilities and the level of utilization of generating and transmission facilities. In addition to the factors 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), (b) changes resulting from conservation and demand-side management programs on the timing and use of electric energy, (c) changes resulting from a national energy policy, (d) 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, (e) the repeal of certain federal statutes that would have the effect of increasing the competitiveness of many IOUs, (f) increased competition from independent power producers and marketers, brokers and federal power marketing agencies, (g) ”self-generation” or “distributed generation” (such as microturbines and fuel cells) by industrial and commercial customers and others, (h) 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, (i) effects of inflation on the operating and maintenance costs of an electric utility and its facilities, (j) changes from projected future load requirements, (k) increases in costs and uncertain availability of capital, (l) shifts in the availability and relative costs of different fuels (including the cost of natural gas and nuclear fuel), (m) 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 California, (n) inadequate risk management procedures and practices with respect to, among other things, the purchase and sale of energy and transmission capacity, (o) other legislative changes, voter initiatives, referenda and statewide propositions, (p) effects of the changes in the economy, (q) effects of possible manipulation of the electric markets, (r) natural disasters or other physical calamities, including, but not limited to, earthquakes and floods and (s) changes to the climate. 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.

NCPA and the Project Participants are unable to predict what impact such factors will have on the business operations and financial condition of the Project Participants' electric systems, but the impact could be significant. This Remarketing Memorandum includes a brief discussion of certain of these factors. 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 2008 Bonds should obtain and review such information.

LITIGATION

There is no controversy or litigation of any nature now pending or threatened restraining or enjoining the issuance, sale, execution or redelivery of the 2008 Bonds, or in any way contesting or affecting the validity of the 2008 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 2008 Bonds.

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 "OTHER 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.

RATINGS

Standard & Poor's Ratings Services, a Standard & Poor's Financial Services LLC business ("Standard & Poor's") and Fitch Ratings ("Fitch") are expected to assign the ratings of "AAA/A-1" and "AA+/F1+", respectively, to the 2008 Series A Bonds and the 2008 Series B Bonds. The long-term "AAA" and "AA+" ratings, respectively, are based jointly on the underlying rating of the 2008 Bonds and the related Letter of Credit issued by the Bank for the benefit of the 2008 Series A Bonds and the 2008 Series B Bonds. The short-term "A-1" and "F1+" ratings assigned to the 2008 Bonds by Standard & Poor's and Fitch, respectively, are based solely on the support provided by the related Letter of Credit. See "THE LETTERS OF CREDIT AND THE REIMBURSEMENT AGREEMENTS." Such ratings reflect only the views of such organizations and an explanation of the significance of such ratings may be obtained only from the applicable rating agency. There is no assurance such ratings will continue for any given period of time or that they will not be revised downward or withdrawn entirely by the rating agencies, if, in the judgment of such rating agencies, 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 affected 2008 Bonds.

FINANCIAL ADVISOR

Public Financial Management Inc. (the "Financial Advisor") has assisted NCPA with various matters relating to the remarketing of the 2008 Bonds. The Financial Advisor is not obligated to undertake, and has not undertaken to make, an independent verification of or to assume responsibility for the accuracy, completeness or fairness of this Remarketing Memorandum. The Financial Advisor is an independent financial advisory firm and is not engaged in the business of underwriting or distributing municipal securities or other public securities.

TAX MATTERS

On April 2, 2008, the date of original issuance and delivery of the 2008 Bonds, Orrick, Herrington & Sutcliffe LLP, Bond Counsel to NCPA in respect of such issuance ("Bond Counsel"), rendered its opinion that, based upon an analysis of existing laws, regulations, rulings and court decisions, and assuming, among other matters, the accuracy of certain representations and compliance with certain covenants, interest on the 2008 Series A Bonds was excluded from gross income of the owners thereof for federal income tax purposes pursuant to section 103 of the Internal Revenue Code of 1986 (the "Code") and was not a specific preference item for purposes of the federal individual or corporate alternative minimum taxes, although Bond Counsel observed that such interest was included in adjusting current earning when calculating corporate alternative minimum taxable income. It was the further opinion of Bond Counsel that interest on the 2008 Bonds was exempt from personal income taxes of the State of California. A complete copy of the opinion of Bond Counsel delivered in connection with the original issuance of the 2008 Bonds is attached as APPENDIX E. The opinion of Bond Counsel has not been updated in connection with the remarketing of the 2008 Bonds or as of the date of this Remarketing Memorandum and Orrick, Herrington & Sutcliffe LLP is not rendering any opinion on the current tax status of the 2008 Bonds.

In its opinion, Bond Counsel noted that the Code imposes various restrictions, conditions and requirements relating to the exclusion from gross income for federal income tax purposes of interest on obligations such as the 2008 Series A Bonds. In connection with the issuance of the 2008 Series A Bonds, NCPA made certain representations and agreements and covenanted to comply with certain restrictions, conditions and requirements designed to ensure that interest on the 2008 Series A Bonds would be excluded from gross income for federal income tax purposes. Bond Counsel noted that inaccuracy of those representations or failure to comply or to have complied with those covenants may result in interest on the 2008 Series A Bonds being included in gross income federal income tax purposes, possibly from the date of original issuance of the 2008 Series A Bonds. The opinion of Orrick, Herrington & Sutcliffe LLP assumed the accuracy of such representations and compliance with such covenants and agreements. Orrick, Herrington & Sutcliffe LLP has not undertaken to determine (or to inform any person) whether any actions taken (or not taken), or events occurring (or not occurring), or any other matters coming to Orrick, Herrington & Sutcliffe LLP's attention after the date of issuance of the 2008 Series A Bonds has adversely affected or may in the future adversely affect the value of, or the tax status of interest on, the 2008 Series A Bonds. Accordingly, the opinion of Orrick, Herrington & Sutcliffe LLP was not intended to, and may not, be relied upon in connection with any such actions, events or matters.

Although Orrick, Herrington & Sutcliffe LLP was of the opinion that interest on the 2008 Series A Bonds is excluded from gross income for federal income tax purposes and that interest on the 2008 Bonds is exempt from State of California personal income taxes, the ownership or disposition of, or the accrual or receipt of interest on, the 2008 Bonds may otherwise affect a Beneficial Owner's federal, state or local tax liability. The nature and extent of these other tax consequences depends upon the particular tax status of the Beneficial Owner or the Beneficial Owner's other items of income or deduction. Orrick, Herrington & Sutcliffe LLP expressed no opinion regarding any such other tax consequences.

Current and future legislative proposals, if enacted into law, clarification of the Code or court decisions may cause interest on the 2008 Series A Bonds to be subject, directly or indirectly, to federal income taxation or to be subject to or exempted from state income taxation, or otherwise prevent Beneficial Owners from realizing the full current benefit of the tax status of such interest. For example, Representative Dave Camp, Chair of the House Ways and Means Committee released draft legislation that would subject interest on the 2008 Series A Bonds to a federal income tax at an effective rate of 10% or more for individuals, trusts, and estates in the highest tax bracket, and the Obama Administration proposed legislation that would limit the exclusion from gross income of interest on the 2008 Series A Bonds to some extent for high-income individuals. The introduction or enactment of any such legislative proposals, clarification of the Code or court decisions may also affect the market price for, or marketability of, the 2008 Series A Bonds. Prospective purchasers of the 2008 Series A Bonds should consult their own tax advisors regarding any pending or proposed federal or state tax legislation, regulations or litigation, as to which Bond Counsel expresses no opinion.

On the date of delivery of the Letters of Credit, Bond Counsel will render an opinion regarding certain matters as required under the Indenture. The form of such opinion is attached as APPENDIX F.

CERTAIN LEGAL MATTERS

On the date of issuance of the 2008 Bonds, Orrick, Herrington & Sutcliffe LLP, Los Angeles, California, Bond Counsel to NCPA, addressed certain legal matters in connection with the authorization and issuance of the 2008 Bonds. A copy of the opinion of Bond Counsel rendered on that date with respect to such matters is attached as APPENDIX E. The opinion of Bond Counsel has not been updated as of the date of this Remarketing Memorandum. Orrick, Herrington & Sutcliffe LLP is also serving as Bond Counsel to NCPA in connection with the remarketing of the 2008 Bonds. Certain legal matters in connection with the remarketing of the 2008 Bonds will also be passed upon for NCPA by Meyers, Nave, Riback, Silver & Wilson, Sacramento, California, General Counsel to NCPA. Fulbright & Jaworski LLP, Los Angeles, California, is serving as disclosure counsel to NCPA in connection with the remarketing of the 2008 Bonds. Certain legal matters will be passed upon for the Bank by its United States counsel, Chapman and Cutler LLP, Chicago, Illinois.

INDEPENDENT AUDITORS

The combined financial statements of Northern California Power Agency and Associated Power Corporations as of and for the years ended June 30, 2013 and June 30, 2012 have been audited by Moss Adams LLP, independent auditors, as stated in their report. Moss Adams 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. Moss Adams LLP has also not performed any procedures relating to this Remarketing Memorandum.

INCLUSION BY SPECIFIC REFERENCE

When delivered by the Remarketing Agent, in its capacity as such, this Remarketing Memorandum shall be deemed to include by specific reference all documents previously provided to the Municipal Securities Rulemaking Board (through EMMA) 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 Remarketing Memorandum to the extent that it is modified or superseded by statements contained in this Remarketing Memorandum or in any other subsequently provided document included by specific reference herein.

MISCELLANEOUS

This Remarketing Memorandum includes descriptions of the terms of the 2008 Bonds, the Indenture, the Third Phase Agreement, 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.

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: /s/ James H. Pope
General Manager

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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.

TABLE OF CONTENTS

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 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 serves the entire area of the City of Alameda and has about 93 pole miles of overhead lines and over 173 cable miles of underground lines. During the fiscal year 2012-13, it served an average of 34,405 customers, comprised of an average of approximately 30,260 residential customers, an average of approximately 3,790 commercial and industrial customers and an average of approximately 355 public authority and other customers, with a peak demand of approximately 68.1 MW.

Alameda joined 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 Alameda Municipal Power's electric utility services. All of Alameda Municipal Power's rights to electric energy, capacity, environmental attributes and transmission are scheduled by NCPA. Alameda participates in the NCPA power pool. See "NORTHERN CALIFORNIA POWER AGENCY—NCPA Power Pool" in the front part of this Remarketing Memorandum.

From June 2001 until November 21, 2008, Alameda 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 "Litigation" and "Condensed Operating Results and Selected Balance Sheet Information" below.

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

Alameda Municipal Power is under the policy control of the Alameda Public Utilities Board, in accordance with the Alameda City Charter. The Public Utilities Board consists of four commissioners appointed by the Mayor with concurrence of the City Council, and the City Manager of the City (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 Public Utilities Board establishes goals and policies, approves major purchases and creates the framework for local control of the utility.

Alameda Municipal Power's main office is located at 2000 Grand Street, Alameda, California 94501, (510) 748-3901. For more information about Alameda and its electric system, contact Glenn Steiger, General Manager at the above address and telephone number. A copy of the most recent comprehensive annual financial report of Alameda Municipal Power (the "Annual Report") is available on Alameda Municipal Power's website at *http://www.alamedamp.com*. 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 Remarketing Memorandum and is not incorporated by reference herein.

Power Supply Resources

The following table sets forth information concerning Alameda's power supply resources and the energy supplied by each during the fiscal year ended June 30, 2013.

CITY OF ALAMEDA
ALAMEDA MUNICIPAL POWER
POWER SUPPLY RESOURCES
For the Fiscal Year Ended June 30, 2013

Source	Capacity Available (MW)[1]	Actual Energy (MWh)	% of Total Energy
Purchased Power[2]:			
Western	13.5	34,266.9	9.00%
High Winds Project	10.0	16,965.3	4.46
Morgan Stanley	15.0	65,520.0	17.21
Landfill Gas Projects			
Richmond	2.0	16,839.6	4.42
Keller Canyon	1.9	14,628.2	3.84
Santa Cruz	1.3	9,609.3	2.52
Ox Mountain (Half Moon Bay) [3]	5.7	12,933.6	3.40
Butte	0.0	9,593.6	2.52
Graeagle	0.4	1,992.5	0.52
NCPA			
Geothermal Plant 1[3]	8.4	22,709.5	5.97
Geothermal Plant 2[3]	8.4	20,729.5	5.45
Hydroelectric Project	24.3	26,773.6	7.03
Combustion Turbine Project No. 1	16.1	166.7	0.04
Combustion Turbine Project No. 2	9.5	416.0	0.11
Other Purchases (net) [3]	--	153,123.6	40.22
Total	116.5	406,267.9	106.72%
Total Capacity and Energy Sold at Wholesale	N/A	(25,564.7)	(6.72)
Alameda's System Requirement for Retail	70.8	380,703.2	100.00%

(1) Non-coincident capacity available.
(2) Entitlements, firm allocations and contract amounts.
(3) Renewable energy sales exchanged for market purchases.

Source: Alameda Municipal Power.

In the fiscal year ended June 30, 2013, Alameda's average cost of power for 363.4 GWh of energy sales was 7.6 cents per kWh, and its average cost of power for the 406.3 GWh purchased was 7.6 cents per kWh.

Purchased Power

Western. Alameda has power purchase agreements with the Western Area Power Administration ("Western") that continue through December 31, 2024. Alameda's Western power is assigned to NCPA for scheduling and delivery to Alameda. 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 (the "Bureau").

On October 5, 2000, Alameda 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 Alameda receiving a "slice of the system" allocation from Western. Alameda's allocation is currently 1.08075% of the CVP output. In 2009, Alameda applied for and was awarded an increase to its allocated percentage of Western

Base Resource hydroelectric deliveries. Effective January 1, 2015, Alameda's current allocation of 1.08075% will increase to 1.20622%. This increased allocation will result in increased deliveries of hydroelectric energy to Alameda customers. Power provided to Alameda under the Western contract is on a take-or-pay basis; Alameda is obligated to pay its share of Western costs whether or not it receives any power.

Other Purchases. Alameda has also entered into certain other power purchase agreements: (i) a power purchase agreement with Morgan Stanley Capital Group for the delivery of 15 MW of power from January 1 through March 31 and from October 1 through December 31 during each of the calendar years 2005-2014; (ii) a power purchase agreement with PPM Energy, Inc. (now Iberdrola Renewables, Inc.) for power supplied from the Highwinds Project in Solano County, California under which Alameda Municipal Power receives 6.17% (approximately 10 MW of the 162 MW project) until June 30, 2028; (iii) five long-term power purchase agreements for power supplied by multiple existing and proposed generating facilities utilizing combustible gaseous emissions from landfills located in or near the San Francisco Bay area, under which (a) Alameda has received approximately 3.5 MW of baseload power from two facilities since early 2006, approximately 7.3 MW of baseload output from two additional facilities since 2009, and approximately 1.9 MW of baseload power from a fifth facility since 2012; and (b) Alameda is expected to receive an additional 10 MW of on-peak power from January 1 through March 31 and from October 1 through December 31 during 2015 and 2016, and 10 MW of on-peak power in January and December and 5 MW of on-peak power in February and November during 2017. In addition, Alameda makes short-term market purchases as necessary or economical to meet its native load requirements.

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

Joint Powers Agency Resources

NCPA. Alameda does not independently own any generation assets but, in addition to power purchased from Western and others, Alameda is a participant in most NCPA projects. Alameda has purchased from NCPA a 10.00% entitlement share in the Hydroelectric Project. Alameda has purchased from NCPA a 19.00% entitlement share in the Capital Facilities Project, Unit One. Alameda has purchased from NCPA a 21.820% entitlement share in the Combustion Turbine Project Number One. Alameda has purchased from NCPA a 16.8825% entitlement share in the Geothermal Project. Alameda has purchased from NCPA a 30.36% entitlement share in the Geysers Transmission Project. For a description of such resources, see "THE HYDROELECTRIC PROJECT" and "OTHER NCPA PROJECTS" in the front part of this Remarketing Memorandum. For each of these NCPA projects in which Alameda participates, Alameda is obligated to pay, on an unconditional take-or-pay basis, 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.

Through NCPA, Alameda also participates in certain power purchase agreements entered into by NCPA, including a power purchase agreement 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 Alameda 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" in the front part of this Remarketing Memorandum.

TANC California-Oregon Transmission Project. Alameda, together with thirteen 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, California ("Redding"), Western, two California water districts and PG&E (collectively, the "COTP Participants") own the California–Oregon Transmission Project (the "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 a cost of approximately $430 million. 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. Alameda did not participate as an acquiring TANC Member for an additional share of the purchased assets from Vernon.

TANC financed its interest in the COTP through the issuance of California-Oregon Transmission Project Revenue Bonds and commercial paper notes, of which approximately $314.2 million principal amount of revenue bonds was outstanding as of June 30, 2014. See "Indebtedness; Joint Powers Agency Obligations" below.

Pursuant to Project Agreement No. 3 for the COTP (the "TANC Agreement"), TANC has agreed to provide to Alameda 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 nondefaulting 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 nondefaulting TANC Member-Participants.

Pursuant to the TANC Agreement, Alameda is obligated to pay 1.2272% of TANC's COTP operating and maintenance expenses and 1.33% of TANC's COTP debt service (on bonds other that TANC's 2009 Series A Bonds on which it is obligated for 1.4496% of debt service and TANC's 2009 Series B Bonds on which it has no obligation for debt service) and is entitled to 1.2272% 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. Alameda's share of annual operating and maintenance expenses and debt service for the COTP is approximately $0.7 million per year. See, however, "—*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 a Pacific Northwest. The Intertie lines are owned by certain of the California investor-owned utilities and Western and are operated by the California Independent System Operator (the "CAISO"). Rate schedules are on file with 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 became a part of the Sacramento Municipal Utility District Western balancing authority area effective December 1, 2005. As a result, the TANC Member-Participants are able to undertake direct scheduling of the COTP within the control area substantially free of the CAISO tariff, charges, congestion and encumbrances.

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 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. Alameda's share of Tesla Midway Service is 6.0 MW. Alameda 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.

COTP Long-Term Layoff. Due to situational and economic changes in value of power deliveries over the COTP, Alameda and six other TANC members intend to layoff their participation shares in the COTP to other TANC members for a period of 25 years. TANC has provided an enabling agreement which became effective on July 1, 2014. The agreement transfers the use and associated rights of Alameda's project participation shares to the receiving parties. 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, Alameda would continue to be a member of TANC and would continue to be 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.

Energy Efficiency and Conservation; Renewable Resources

State laws enacted in 2005 and 2006 require publicly-owned utilities ("POUs"), such as Alameda Municipal Power, 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. Assembly Bill 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.

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

Alameda Municipal Power 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. Alameda Municipal Power offers energy efficiency programs for all of its customer classes and has established an aggressive target for reducing future consumption by nearly 8% during the next ten years.

Future Power Supply Resources

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

Interconnections, Transmission and Distribution Facilities

Alameda's electric system is interconnected with the system of PG&E at two PG&E substations. Alameda 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 258.6 miles of 12 kV distribution lines (approximately 67% of which are underground) and fourteen substations. Alameda's electric system experienced approximately 7.2 minutes of outage time per customer in fiscal year 2012-13.

Forecast of Capital Expenditures

Alameda'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

Fiscal Year Ended June 30,				
2014	2015	2016	2017	2018
$4,015,000	$5,129,359	$4,952,000	$4,021,000	$4,106,000

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. Alameda anticipates funding the majority of such costs from current year revenues.

Insurance

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. In the property program, Alameda carries "all risk" (excluding flood and earthquake) replacement cost property coverage for both real and personal property, subject to a $25,000 deductible. Associated with that coverage, AMP carries $10 million in boiler and machinery coverage. Finally, Alameda carries workers' compensation coverage with statutory limits, in excess of a $350,000 self-insured retention through LAWCX.

Employees

As of June 30, 2014, approximately 93 City of Alameda employees were assigned specifically to the Alameda electric utility. Effective February 23, 2014, AMP's management personnel are represented by the Electric Utility Professionals of Alameda ("EUPA") instead of the Management and Confidential Employees Association ("MCEA"). 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 with each of EUPA, ACEA and IBEW expires in December 2015. There have been no strikes or other work stoppages at the City of Alameda, including Alameda Municipal Power, since the early 1970s.

Retirement benefits to City of Alameda employees, including those assigned to Alameda Municipal Power, 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. Employees of the City assigned to Alameda Municipal Power participate in the CalPERS Miscellaneous Plan. CalPERS determines contribution requirements for the plan using a modification of the Entry Age Normal Method. Under this method, the City of Alameda's total normal benefit cost for each employee from date of hire to date of retirement is expressed as a level percentage of the related total payroll cost. Normal benefit cost under this method is the level amount the employer must pay annually to fund an employee's projected retirement benefit. This level percentage of payroll method is used to amortize any unfunded actuarial liabilities. The actuarial assumptions used to compute the contribution requirements are also used to compute the actuarial accrued liability. 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.

CalPERS uses the market related value method of valuing the plan's assets. An investment rate of return of 7.50% is assumed, including inflation at 2.75%. Annual salary increases are assumed to vary by duration of service. Changes in liability due to plan amendments, changes in actuarial assumptions, or changes in actuarial methods are amortized as a level percentage of payroll on a closed basis within twenty years. Investment gains and losses are accumulated as realized, 10% of the net balance is amortized annually. CalPERS issues a separate comprehensive annual financial report. Copies of the CalPERS annual financial report may be obtained from the CalPERS Executive Office, 400 Q Street, Sacramento, California 95814.

The City of Alameda's actuarially required contributions for the three fiscal years 2010-11 through 2012-13 were as follows: fiscal year 2010-11, $12,082,061 (of which $850,135 was contributed by the electric utility); fiscal year 2011-12, $13,449,867 (of which $1,006,355 was contributed by the electric utility); and fiscal year 2012-13, $13,572,530 (of which $970,641 was contributed by the electric utility). The City of Alameda made these contributions as required, together with certain additional immaterial amounts required as a result of the payment of employee compensations. As of June 30, 2012 (the most recent actuarial data available), the entry age accrued liability for the Miscellaneous Plan (in which City of Alameda employees assigned to Alameda Municipal Power participate) was $219,802,218, the actuarial value of assets was $194,595,559, resulting in an unfunded liability of $25,206,659, with a funded ratio of 88.5%. The portion of the plan allocable to Alameda Municipal Power employees, which is part of the City of Alameda's liability pool, is not separately calculated.

On April 17, 2013 the CalPERS Board of Administration approved new actuarial policies aimed at fully funding the pension system's obligations within 30 years. The new policies include a rate-smoothing method with a 30-year fixed amortization period for gains and losses. CalPERS announced that, based on investment return simulations performed for the next 30 years, increasing contributions more rapidly in the short term is expected to result in almost a 25% improvement in funded status over a 30-year-period. The new amortization schedule will be used to set contribution rates for public agency employers in the State beginning in the 2015-16 fiscal year. This delay is intended to allow the impact of the changes to be built into the projection of employer contribution rates and afford employers with additional time to adjust to the changes.

According to CalPERS, the new policies will result in an increased likelihood of higher peak employer contribution levels in the future but will not significantly increase average contribution levels. The median employer contribution rate over the next four years is expected to be higher. In the long-term, however, higher funded levels may result in lower employer contributions.

On February 20, 2014, the CalPERS Board of Administration adopted new mortality and retirement assumptions as part of a regular review of demographic experience. Key assumption changes included longer post-retirement life expectancy and earlier retirement ages. The impact of the assumption changes will be phased in over five years, with a twenty-year amortization, beginning in the 2016-17 fiscal year. CalPERS has estimated that the adoption of the new assumptions will increase employer contribution rates (as a percentage of payroll) for most Miscellaneous Plans in the range of by 0.4% to 1.9% in the 2016-17 fiscal year and in the range of by 1.0% to 6.7% by 2020-21, depending on the benefit formula applicable to active members.

In addition, the City of Alameda provides certain post-employment benefits other than pensions (OPEB) to City employees, including those assigned to the Alameda Municipal Power, who retire from the City and receive a CalPERS pension through its participation in the CalPERS medical and dental benefits program. Contribution requirements of the postemployment benefit are based on pay-as-you-go financing. The City's annual required contribution of the employer ("ARC") was determined as part of a January 1, 2013 actuarial valuation using the Entry Age Normal Actuarial Cost Method. This is a projected benefit cost method which takes into account those benefits that are expected to be earned in the future as well as those already accrued. The actuarial assumptions include (a) a 4.0% investment rate of return; and (b) a healthcare trend of declining annual increases ranging from 8.3% in 2014 to 5% for years starting 2021. The actuarial methods and assumptions use techniques that "smooth" the effects of short-term volatility in actuarial accrued liabilities and the actuarial value of assets. Actuarial calculations reflect a long-term perspective and actuarial valuations involve estimates of the value of reported amounts and assumptions about the probability of events far into the future. Actuarially determined amounts are subject to revisions at least biannually, as results are compared to past expectations and new estimates are made about the future. The City's OPEB unfunded actuarial accrued liability as of June 30, 2013 is being amortized using a 26-year closed amortization period. Assumption changes, plan changes and gains or losses are being amortized using a 15-year closed period. For the fiscal years 2010-11, 2011-12 and 2012-13, the City of Alameda contributed 36%, 33% and 35%, respectively, of the annual OPEB cost of $6,193,000 (fiscal year 2010-11), $7,340,000 (fiscal year 2011-12) and $7,650,115 (fiscal year 2012-13), respectively. Amounts contributed for such fiscal years were as follows: fiscal year 2010-11, $2,255,039 (of which $46,862 was contributed by the electric utility); fiscal year 2011-12, $2,424,959 (of which $48,970 was contributed by the electric utility); and fiscal year 2012-13, $2,659,689 (of which $55,200 was contributed by the electric utility). As of January 1, 2013, the entry age actuarial accrued liability for the health care benefits plan was $91,172,000, the actuarial value of assets was $0, resulting in an unfunded liability of $91,172,000.

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

Service Area

The largest employers in Alameda as of June 30, 2013 are as follows:

CITY OF ALAMEDA
2012-13 LARGEST EMPLOYERS

Employer	Business	Number of Employees
Telecare Corp	Mental Health Provider	2,100
Alameda Unified School District	Education	1,330
North Face Inc.	Retail	600
City of Alameda	Local Government	502
Alameda Hospital	Hospital	492
Celera Corp	Surgical and Medical Instrument Mfg	490
Associated Third Party Administrators	Benefits Administration	450
Bay Ship & Yacht Company	Construction and Repair	250
College of Alameda	Education	216
Bay View Nursing & Rehab Center	Managed Care Facility	180

Source: City of Alameda Finance Department.

The following table reflects the five-year history of building permit valuation for the City:

CITY OF ALAMEDA
BUILDING PERMITS AND VALUATIONS
Calendar Years 2009 through 2013
(dollars in thousands)

	2009	2010	2011	2012	2013
Permit Valuation					
New Single-family	$ 879	$ 5,985	$ 8,199	$ 1,367	$ 545
New Multi-family	0	0	0	0	0
Res. Alterations/Additions	10,553	11,466	18,478	10,653	20,806
Total Residential	$11,432	$17,451	$26,677	$12,020	$21,351
New Commercial	$ 0	$ 0	$15,967	$ 0	$ 1,959
New Industrial	0	0	0	0	162
New Other	727	528	1,328	1,812	1,584
Comm. Alterations/Additions	1,417	1,266	19,879	9,424	15,794
Total Nonresidential	$2,144	$1,794	$37,174	$11,236	$19,499
New Dwelling Units					
Single Family	3	16	24	4	1
Multiple Family	0	0	0	0	0
Total	3	16	24	4	1

Source: Construction Industry Research Board.

The five-year history of assessed valuations in Alameda is as follows:

CITY OF ALAMEDA
TOTAL ASSESSED VALUATIONS
(Fiscal Years 2009-10 through 2013-14)

2009-10	2010-11	2011-12	2012-13	2013-14
$9,436,632,497	$9,284,599,251	$9,387,095,373	$9,423,046,773	$9,382,225,607

Source: City of Alameda Finance Department.

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; 2011-2014 as of January 1)

	City of Alameda	County of Alameda	State of California
1970	70,968	1,071,446	19,971,069
1980	63,852	1,105,379	23,668,562
1990	73,979	1,276,702	29,760,021
2000	73,713	1,443,939	33,873,086
2010	73,812	1,510,271	37,253,956
2011	74,052	1,517,756	37,427,946
2012	74,546	1,530,206	37,668,804
2013	75,197	1,550,119	37,984,138
2014	75,988	1,573,254	38,340,074

Sources: U.S. Bureau of Census and California State Department of Finance.

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.

On November 18, 2008, the City Council of the City unanimously authorized the sale of Alameda's telecommunications business line effective as of November 21, 2008. The sale price of the telecommunications business line was significantly less than the aggregate carrying values of the telecommunications division's assets. The telecommunications division capital assets and operations were financed in part from proceeds of the utility's Telecom System Revenue Taxable Certificates of Participation, Series 2002A (the "2002 Telecom COPs") and Telecom System Revenue Bonds Anticipation Notes, Series 2004 (the "2004 Telecom Notes").

Vectren Communications Services, Inc. ("VCS"), holder of the 2002 Telecom COPs in the amount of $6.3 million, sued Alameda Municipal Power, along with the City of Alameda, in 2008 in the United States District Court for the Northern District of California. VCS's suit alleged, among other things, that Alameda Municipal Power breached its obligations under the installment sale agreement entered into in 2002, and amended and restated in 2004, to properly manage the telecommunications system and to charge appropriate rates, resulting in the non-payment of installments from net telecom revenues to sufficiently fund payment of the 2002 Telecom COPs in the amount of $6.3 million, plus accrued interest at a 9% default rate, for total damages of over $10 million. VCS amended its complaint in early 2009 to allege an additional breach of contract claim, based upon Alameda's sale of its telecommunications business in November 2008 without VCS's consent. At the conclusion of a trial in 2010, the jury rejected four out of five of VCS's claims against Alameda Municipal Power, awarding damages of approximately $1.9 million on VCS's remaining claim. Both sides appealed. In August 2013, the United States Court of Appeals for the Ninth Circuit reversed the jury's verdict and entered judgment in favor of Alameda Municipal Power.

On VCS's sale claim, however, the Ninth Circuit remanded the matter to the District Court for a determination of damages. Following remand, both sides filed motions for summary judgment. On February 7, 2014, the District Court issued its order on the motions, agreeing with Alameda that, as a result of the Ninth Circuit's ruling and the "firewall" under which VCS was contractually limited to a recovery from telecom assets, VCS could not prove any damages arising from the telecom system sale. Left undecided, however, was whether there were any issues remaining for trial. On March 31, 2014, after further briefing, a final judgment for the City of Alameda and against VCS was entered by the District Court, thus resolving in Alameda's favor all remaining claims. On April 30, 2014, VCS appealed that decision. The parties have agreed to a briefing schedule through the end of 2014 with no date yet set for hearing.

Nuveen Municipal High Income Opportunity Fund, the Nuveen High Yield Municipal Bond Fund, Pacific Specialty Insurance Company (collectively, "Nuveen"), and the Bernard Osher Trust ("Osher") filed separate litigation against Alameda Municipal Power based on their purchases of the 2004 Telecom Notes. Nuveen and Osher asserted state and federal law securities fraud claims alleging that Alameda failed to fully disclose material facts relating to issuance of the 2004 Telecom Notes in 2004. Nuveen and Osher claimed combined damages in excess of $15 million, in addition to prejudgment interest and other items that, if allowed, could have exceeded $4 million. Alameda disputed Nuveen's and Osher's entitlement to any such amounts. In September 2010 and January 2011, Alameda filed motions for summary judgment against all of Nuveen's and Osher's claims. On May 16, 2011, the Court granted Alameda's motions as to all of Nuveen and Osher's claims. Following summary judgment, Alameda filed a motion for recovery of defense costs, totaling $1.5 million, which the Court denied. Alameda filed a bill of costs seeking an award of $132,000 in costs, for which a judgment was entered awarding $91,516 to Alameda against Nuveen and Osher jointly and severally. Osher's claims against Alameda have been resolved in Alameda's favor as Osher did not appeal the district court's summary judgment on all claims. The district court awarded Alameda approximately $92,000 in costs, which Osher paid to Alameda in October 2012.

Nuveen appealed the district court's summary judgment. On September 19, 2013, the United States Court of Appeals for the Ninth Circuit affirmed the judgment in the Nuveen matter in favor of Alameda Municipal Power in full. Nuveen did not seek further review of the decision and the time for all appeals has expired.

Other present lawsuits and other claims concerning Alameda'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 Alameda Municipal Power'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 Alameda Municipal Power.

Rates and Charges

Alameda Municipal Power 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.

Alameda's fiscal year 2013-14 average rate per kWh sold for all electric service is estimated to be 14.4 cents per kWh. The average rate per kWh sold for residential service in fiscal year 2013-14 is estimated to be 14.8 cents. The average rates for commercial and industrial service are estimated to be 14.5 and 12.8 cents per kWh, respectively. Alameda's average rate for municipal and public authority service for fiscal year 2013-14 is estimated at 14.5 cents per kWh. In general, the rate adjustment for fiscal year 2013-14 was designed to increase revenue in each service category by 0.4 cents per kWh. Currently, Alameda management estimates that Alameda's electric rates are approximately 14.7% below those in the surrounding area on average. On April 21, 2014, the Alameda Public Utilities Board approved a 2.00% average rate increase for fiscal year 2014-15 that took effect on July 1, 2014.

The following table presents a recent history of Alameda's rate changes. Alameda also imposes a solar surcharge in conjunction with its electric rates which is applied to fund its photovoltaic incentive programs as required by Senate Bill 1 (the California Solar Initiative).

CITY OF ALAMEDA
ALAMEDA MUNICIPAL POWER
ELECTRIC RATE CHANGES

Date	Percent Change (Average)
July 1, 2014	2.00%
July 1, 2013	3.25
July 1, 2012	3.25
July 1, 2011	3.85
July 1, 2010	3.75
July 1, 2009	0.09[1]

(1) 2.50% rate increase of MU-1 rate only.
Source: Alameda Municipal Power.

Largest Customers

Alameda's ten largest electric customers in terms of kWh sales for the fiscal year ended June 30, 2013 accounted for 22.3% of total kWh sales and 22.3% of total revenues. The largest customer accounted for 4.8% of total kWh sales and 4.6% of total revenues. The smallest of the ten largest customers accounted for 1.2% of total kWh sales and 1.1% 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 2008-09 through 2012-13, are listed below.

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

	Fiscal Years Ended June 30,				
	2009	2010	2011	2012	2013
Number of Customers:					
Residential	30,119	30,191	30,171	30,194	30,260
Commercial	3,782	3,818	3,744	3,776	3,781
Industrial	11	18	13	12	9
Public Authority	333	342	330	327	331
Other	27	30	23	29	24
Total Customers	34,272	34,399	34,281	34,338	34,405
Kilowatt-Hour Sales:					
Residential	140,048,081	142,109,998	142,305,884	139,665,283	135,924,914
Commercial	184,300,489	179,960,145	174,717,111	172,445,087	176,259,228
Industrial	45,611,047	44,243,371	49,235,786	45,512,960	35,487,830
Public Authority	14,675,829	13,598,342	13,138,014	12,880,649	12,585,314
Other	3,041,330	3,207,924	3,240,179	3,283,309	3,186,846
Total kWh sales	387,676,776	383,119,780	382,636,974	373,787,288	363,444,132
Revenues from Sale of Energy:					
Residential	$17,365,563	$17,647,604	$18,257,650	$18,488,086	$18,781,411
Commercial	23,644,464	23,090,891	23,352,114	23,964,056	24,967,214
Industrial	5,175,117	5,026,286	5,861,554	5,666,350	4,552,958
Public Authority	1,820,996	1,749,835	1,753,399	1,793,977	1,779,313
Other	451,524	461,947	641,967	464,788	623,308
Total Revenues from Sale of Energy	$48,457,664	$47,976,563	$49,866,684	$50,377,257	$50,704,204
Peak Demand (kW)	76,250	73,712	70,800	67,188	68,100

Source: Alameda Municipal Power.

Indebtedness; Joint Powers Agency Obligations

As of June 30, 2014, Alameda 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 Alameda Municipal Power, in the aggregate principal amount of $28,685,000, the installment payments payable by Alameda under which are payable from and secured solely by a pledge of and lien on net revenues of the electric system of Alameda Municipal Power. These obligations are subordinate to the payments required to be made with respect to Alameda's obligations to NCPA and TANC as described below. Obligations relating to Alameda's telecommunications enterprise are payable solely from revenues of the telecommunication enterprise and therefore are not included in this total.

As previously discussed, Alameda participates in certain joint powers agencies, including NCPA and TANC. Obligations of Alameda with respect to TANC and NCPA constitute operating expenses of Alameda payable prior to any of the payments required to be made by Alameda's 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 Alameda to pay a share of the obligations of a defaulting participant. Alameda'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 June 30, 2014)

	Outstanding Debt[(1)]	Alameda's Participation[(2)]	Alameda's Share of Outstanding Debt[(1)]
NCPA			
Geothermal Project	$ 41.3	16.88%	$ 7.0
Hydroelectric Project	401.2	10.00[(3)]	41.2[(3)]
Capital Facilities Project Unit One	48.1	19.00	9.1
TANC			
Bonds	314.2	1.33[(4)]	4.0[(4)]
TOTAL[*]	$804.8		$61.3

[*] 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) Alameda's actual payments represent approximately 10.26% of outstanding debt service as a result of credit to non-participating members with respect to portion of debt obligation.
(4) As described herein, Alameda's actual payment 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. As described herein, effective July 1, 2014, Alameda has entered into an agreement to layoff to other TANC Member-Participants' for 25 years its COTP interest which will effectively reduce Alameda's payment obligation for the outstanding debt to $0. Alameda remains contractually obligated for its full participation share. See "Power Supply Resources–Joint Powers Agency Resources–TANC California-Oregon Transmission Project."

Source: Alameda Municipal Power.

For the fiscal year ending June 30, 2013, Alameda estimates its payment obligations for debt service on its joint powers agency debt obligations aggregated approximately $5.9 million and approximately $5.9 million for the fiscal year ending June 30, 2014. It should be noted that the COTP amount of Alameda's share of the debt will be 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. In connection with certain of such joint power agency obligations, the respective joint powers agency has entered into interest rate swap agreements relating thereto for the purposes of substantially fixing the interest cost with respect thereto. There is no guarantee that the floating rate payable to the respective joint powers agency pursuant to each of the interest rate swap agreements relating thereto 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 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 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 Alameda).

Transfers to the General Fund

The Alameda City Charter provides that Alameda Municipal Power transfer to the City General Fund 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 the Alameda Municipal Power from earnings of the Electric System, all as defined in and provided pursuant to the terms of the City Charter. In the absence of such transfer of excess earnings as determined under the City Charter, the Public Utilities Board has authorized by resolution certain contributions from the Electric System to the City General Fund in accordance with the provisions of the City Charter.

The following table sets out the transfers from the Electric System Alameda Municipal Power's General Fund for the five fiscal years 2008-09 through 2012-13.

CITY OF ALAMEDA
ALAMEDA MUNICIPAL POWER
TRANSFERS TO THE GENERAL FUND
(Dollar Amounts in Thousands)

Fiscal Year	Transfer Amount
2008-09	$2,800,000
2009-10	2,800,000
2010-11	2,800,000
2011-12	2,800,000
2012-13	2,800,000

Source: Alameda Municipal Power.

Significant Accounting Policies

Alameda's most recent Component Unit Financial Statements for the fiscal years ended June 30, 2013 and 2012 were audited by Vavrinek, Trine, Day & Company, LLP, Pleasanton, California, in accordance with generally accepted auditing standards. The audited financial statements contain opinions that the financial statements present fairly the financial position of Alameda Municipal Power. 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 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 Municipal Power 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.

Alameda Municipal Power'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.

Alameda Municipal Power'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 Alameda's electric utility for the five fiscal years 2008-09 through 2012-13. The information for the fiscal years ended June 30, 2009 through June 30, 2013 was prepared by Alameda on the basis of its audited financial statements for such years. The historical debt service coverage ratios have been calculated in accordance with Alameda's Electric System Installment Sale Agreement.

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

	Fiscal Years Ended June 30				
	2009	2010	2011	2012	2013
Electric System Revenues					
Sales of Electricity	$48,457,664	$47,976,563	$49,866,684	$50,377,257	$50,704,204
Other Revenues [1]	2,563,353	1,563,939	616,190	1,321,719	5,727,518[10]
Total Electric System Revenues	$51,021,017	$49,540,502	$50,482,874	$51,698,976	$56,431,722
Operation and Maintenance Costs					
Purchased Power [2][3]	$30,700,344	$29,147,084	$25,159,235	$25,878,402	$28,544,844
Energy Efficiency, Solar and Other	736,150	1,200,496	954,695	1,253,443	1,241,434
Operations & Maintenance	4,645,057	3,833,191	3,871,026	3,879,446	3,871,957
Customer Service, Information Systems	1,668,302	1,779,098	1,954,610	2,000,961	2,005,147
Administrative & General	5,846,612	5,284,904	5,289,861	5,507,435	6,114,615
Customer Relations	406,514	484,693	510,427	492,889	628,344
Jobbing Sales Expense	971,303	232,121	154,501	216,243	239,946
Balancing Account Adjustment	(434,508)	(2,211,428)	(303,406)	4,055,622	2,318,595
Total Operation and Maintenance Costs	$44,539,774	$39,750,159	$37,590,949	$43,284,442	$44,964,882
Net Revenues[4]	$ 6,481,243	$ 9,790,343	$12,891,925	$ 8,414,534	$11,466,840
Rate Stabilization Fund Transfers	--	--	--	--	(4,283,423)
Use of Reserves	--	--	--	--	--
Adjusted Annual Net Revenues	$ 6,481,243	$ 9,790,343	$12,891,949	$ 8,414,534	$ 7,183,417
Debt Service	$ 2,925,766	$ 2,996,590	$ 1,637,194[8]	$ 2,630,624	$ 2,753,097
Debt Service Coverage [5]	2.22	3.27	7.87[8]	3.20	2.61
Amount Available After Debt Service	$ 3,555,477	$ 6,793,753	$11,254,731	$ 5,783,910	$ 4,430,320
Selected Balance Sheet Information:					
(in thousands)					
Unrestricted Cash & Investments[6]	$ 43,809	$ 52,976[9]	$ 46,629[9]	$ 48,757	$ 50,095
Rate Stabilization Fund Balance[7]	--	--	--	--	4,283
Net Plant in Service	39,370	39,058	37,113	35,561	34,285
Construction Work in Progress	3,054	2,262	1,719	1,501	1,878
Electric Utility Plant-Net	42,424	41,167	38,833	37,063	36,163
Outstanding Electric System Debt[7]	39,045	39,045[8]	31,685[8]	30,790	29,750

(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.
(3) Purchased Power costs reflect inclusion of prior year budget settlements from NCPA.
(4) Excluding Payments in lieu of taxes and depreciation.
(5) Adjusted Annual Net Revenues divided by debt service.
(6) Includes General Reserve balance held at NCPA. See also "Available Reserves" below.
(7) Includes renewable energy credit sales and cap and trade auction sales placed into reserve for Rate Stabilization Fund.
(8) Excludes debt service related to electric system certificates of participation retired from reserves as described in footnote (9) below.
(9) Alameda Municipal Power used approximately $8.8 million of the cash and equivalents held for Alameda Municipal Power in its NCPA General Reserve in August 2010 in connection with the refunding of its then outstanding $39.0 million electric system certificates of participation. In August 2010, Alameda Municipal Power refunded its then outstanding electric system revenue certificates of participation through the issuance of $31.7 million aggregate principal amount of Alameda Public Financing Authority Revenue Bonds, 2010 Series A (Alameda Municipal Power Refinancing) and Taxable Revenue Bonds, 2010 Series B (Alameda Municipal Power Refinancing). See "Indebtedness; Joint Powers Agency Obligations" above.
(10) Includes $4.28 million in renewable energy credit and cap and trade sales.

Source: Alameda Municipal Power.

Interfund Transfers. During the fiscal year 2008-09, $1,095,614 in interfund transfers (*i.e.* no repayment expected) from the Electric System enterprise fund to the telecommunications system enterprise fund were recorded for expenses due to the sale of the Alameda's telecommunications system on November 21, 2008. During the fiscal year 2009-10, 2010-11, 2011-12, 2012-13, additional interfund transfers from the Electric System enterprise fund to the telecommunications system enterprise fund amounted to $2,734,279, $2,929,410, $987,222 and $206,429, respectively, for expenses. Alameda Municipal Power has indicated that an additional $581,343 was paid by the Electric System enterprise fund for telecommunications system enterprise fund litigation expenses during fiscal year 2013-14. See "Litigation" above.

Available Reserves. As of June 30, 2013, the balance in cash and equivalents available at Alameda Municipal Power was $29,016,108. In addition, Alameda had available in reserve accounts held by NCPA an additional $15,551,397 as of such date.

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 13.92 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. The members of the City Council are elected City-wide for staggered four year 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, NCPA's Central Dispatch Center in Roseville provides real-time dispatching and scheduling of all available resources to serve Lodi's electric load.

The electric system serves the entire area of the City of Lodi (approximately 13.92 square miles) and has over 147 miles of overhead lines and over 159 miles of underground lines. During the fiscal year ended June 30, 2013, the Lodi electric system served 25,556 customers, comprised of 22,369 residential customers, 2,941 commercial/industrial customers and 246 other customers. On July 24, 2006, an all-time, historical high peak demand of 140.4 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 Liz Kirkley, Electric Utility Director, at the above address and telephone number. A copy of the most recent comprehensive annual financial report of the City of Lodi (the "Annual Report") is available on Lodi's website at *http://www.lodi.gov*. 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 Remarketing Memorandum 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, 2013.

CITY OF LODI
ELECTRIC UTILITY DEPARTMENT
POWER SUPPLY RESOURCES
For the Fiscal Year Ended June 30, 2013

Source	Capacity Available (MW)[(1)(5)]	Actual Energy (MWh)	% of Total Energy
Purchased Power[(2)]:			
Western	4.7	15,720	2.99%
NCPA			
Geothermal Project	13.3	87,354	16.59
Hydroelectric Project	26.2	27,764	5.27
Combustion Turbine Project No. 1	9.4	102	0.02
Capital Facilities, Unit One	19.6	865	0.16
Lodi Energy Center[(3)]	26.6	64,453	12.24
Contracts, Exchanges and Bilaterals[(4)]	70.0	330,290	62.73
Total	169.8	526,548[(5)(6)]	100.00%
Total Capacity and Energy Sold at Wholesale	N/A	74,223	
Lodi System Requirement for Retail	143.2	452,325	

(1) Non-coincident capacity available.
(2) Entitlements, firm allocations and contract amounts.
(3) Lodi Energy Center commenced commercial operation on November 27, 2012.
(4) Includes participation in NCPA/Seattle City Light exchange. See “OTHER NCPA PROJECTS—Power Purchase Contracts” in the front part of this Remarketing Memorandum.
(5) Units at Backbone Output.
(6) Includes supply from exchanges and line losses.
Source: City of Lodi.

In the fiscal year ended June 30, 2013, Lodi’s average cost of power delivered to the Lodi electric system was $0.0875 cents per kWh.

Purchased Power

Western. Lodi has an agreement with Western, which expires December 31, 2024, to purchase a base resource of 0.49049% of the Central Valley Project output. On January 1, 2015, Lodi’s allocation will increase to 0.55189%. Energy provided to Lodi under the Western contract is on a take-or-pay basis; Lodi is obligated to pay its share of Western costs whether or not it receives any power. Energy associated with the base resource from Western is scheduled by NCPA for Lodi’s benefit. For the fiscal year ended June 30, 2013, the average melded cost of delivered power under contracts with Western was approximately $41.18 per MWh.

Other Purchases. Lodi has a 25 MW share of the NCPA Seattle City Light exchange arrangement (included under Contracts, Exchanges and Bilaterals in the table above), which is transmitted to Lodi via its COTP scheduling entitlement (described below). NCPA has provided notice to Seattle City Light of the termination of this arrangement effective in 2018. Other power purchases for fiscal year 2012-13 were short-term. NCPA schedules daily and hourly (spot) power purchases and sales to balance Lodi’s resources with its native load requirements. Due to Lodi’s layoff of its share of COTP effective July 1, 2014 (See “TANC California-Oregon Transmission Project”), Lodi will utilize other options related to its Seattle City Light exchange arrangement including, but not limited to selling its share to other NCPA members and/or other market participants. See also “OTHER NCPA PROJECTS” in the front part of this Remarketing Memorandum.

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 most NCPA projects. Lodi has purchased from NCPA a 10.37% entitlement share in the Hydroelectric Project. Lodi has purchased from NCPA a 39.50% entitlement share in the Capital Facilities Project, Unit One. Lodi has purchased from NCPA a 10.28% entitlement share in the Geothermal Project. Lodi has purchased from NCPA an 18.48% entitlement share in the Geysers Transmission Project. Lodi has purchased from NCPA a 13.39% entitlement share in the Combustion Turbine Project Number One (exclusive of the portion acquired by the City of Roseville). Lodi has purchased from NCPA a 9.5% generation entitlement share in NCPA's Lodi Energy Center Project. For a description of such resources, see "THE PROJECT" and "OTHER NCPA PROJECTS" in the front part of this Remarketing Memorandum. For each of these NCPA projects in which Lodi participates, Lodi is obligated to pay, on an unconditional take-or-pay basis, 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.

TANC California – Oregon Transmission Project. Lodi is a member of the Transmission Agency of Northern California ("TANC") and has executed the TANC Agreement for a participation percentage 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 (approximately 121 MW) of the City of Vernon, California ("Vernon"), one of the original owners of the COTP. TANC utilized a combination of cash and the issuance of commercial paper (which was subsequently refunded with bonds) to fund the acquisition of Vernon's COTP transmission assets (the "Vernon acquisition debt"). Lodi, as well as the other acquiring TANC Members, began scheduling the acquired COTP transmission transfer capability on April 8, 2008. 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—Joint Powers Agency 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 transmission service, effective July 1, 2014, whereby Lodi and all of the TANC Members who are in the balancing authority area of the California Independent System Operator Corporation ("CAISO") will lay off their interests to other COTP participants who are in the balancing authority area of the Balancing Authority of Northern California. These entities will pay Lodi's current allocated share of COTP costs and following the retirement of the COTP debt service in approximately 10 years, will, in addition, begin making annual payments to Lodi in the amount of approximately $230,000 per year. Approval of this agreement does not change Lodi's membership status in TANC. 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. See "CITY OF ALAMEDA—Joint Powers Agency Resources—*TANC Tesla-Midway Transmission Service*" for a further description of the Tesla-Midway Transmission Service.

Renewable Resources

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") and the California Global Warming Solutions Act of 2006 (the "GWSA"). See "DEVELOPMENTS IN THE CALIFORNIA ENERGY MARKETS—State Legislation—*Greenhouse Gas Emissions – Global Warming Solutions Act*" and "—*Renewable Portfolio Standards*" in the front part of this Remarketing Memorandum. Lodi's current renewable power resources include geothermal, solar and small hydro.

With its existing power resources and historic carryover, Lodi anticipates meeting its Renewable Portfolio Standard ("RPS") requirements through 2018. Participation in a new solar energy project (described below) approved by the Lodi City Council on June 18, 2014 will help meet Lodi's RPS obligation through 2020.

The Astoria 2 Solar Project is a 75 MW photovoltaic plant being developed by Recurrent Energy, to be located in the southeastern portion of Kern County. The project is a second phase of a larger project that was developed for PG&E and will interconnect with the CAISO's system at the Whirlwind substation. Recurrent Energy has the third largest market share of utility scale solar projects in California and the project has already received pre-certification by the California Energy Commission ("CEC") as a RPS eligible facility and is a party to a large generator interconnection agreement allowing for full capacity deliverability status with resource adequacy benefits.

The contract term for the Astoria 2 Solar Project is 20 years, with an estimated commercial operation date of December 31, 2016. Energy from this project is guaranteed to qualify as Portfolio Content Category 1 energy under RPS. Lodi's share of the purchase is 13.3333%, or 10 MW which is enough energy to meet about 7% of Lodi's retail load. Combined with existing generation resources and historic carryover, this project will enable Lodi to meet its RPS obligations through 2020.

The cost of power from the Astoria 2 Solar Project is fixed at $64/MWh for the 20-year life of the project. The price is only paid for energy actually delivered. Lodi will not have ownership in the project and will not incur any capital expenditures.

Future Power Supply Resources

Based upon its current forecasted sales growth, resource mix and market prices, Lodi believes its annual balance-of-month, day-ahead, and hour-ahead purchases will be less than 25% of total energy requirements for the next two years. Lodi's interest in NCPA's Multiple Capital Facilities Project Unit One and NCPA's Combustion Turbine Project Number One provide 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. Lodi's 9.5% generation entitlement share in NCPA's Lodi Energy Center, a 280 MW combined-cycle plant, which became commercially operable on November 27, 2012, replaced a series of 25 MW contracts procured by Lodi that terminated in March 2012. In addition, due to the long lead time in acquiring certain resources, including renewable resources, Lodi, through NCPA, continues to consider additional projects that might be included in its resource mix. Lodi has joined NCPA's Market Purchase Program under which NCPA may purchase power for Lodi for up to five year terms.

Energy Efficiency and Conservation

Since 1998, Lodi has maintained 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 utility rebates for insulation, improved air duct systems, high-efficiency air conditioners, attic fans, whole-house fans, white/cool roofing materials, radiant barriers, refrigeration efficiency improvements, EnergyStar appliances, pump/motor/process equipment improvements, lighting retrofits, and appliance recycling programs.

Lodi also provides energy education for residential and non-residential customers, including on-site and on-line energy audits, and hosts a number of programs to promote renewable energy education and outreach. As part of its education and outreach efforts, Lodi gives in-classroom presentations on solar and other renewable energy sources, co-sponsors the Youth Energy Summit, and offers the Lodi Energy Smart Workshop series.

Over 50,000 Lodi utility customers have been 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 (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 292 miles of 12 kV distribution lines (approximately 54% of which are underground) and four substations. Lodi's system experiences approximately 31 minutes of outage time per customer per year.

Forecast of Capital Expenditures

Lodi's five-year capital projection for the electric facilities contemplates potential capital expenditures for substation upgrades, streetlight improvements, ongoing overhead and underground maintenance, and related system reliability projects. In addition, Lodi is embarking on a project to upgrade the interconnection between its electric distribution system and the adjacent transmission grid to provide sufficient capacity to serve Lodi's projected electrical load growth. The project will reduce Lodi's transmission access charges once completed. Lodi anticipates funding such capital costs from rate revenues, special development fees and possible new debt issuance as required. Over the next five years, total capital expenditures could range from $18 million to $38 million depending on the actual projects undertaken and their timing.

Employees

As of July 1, 2014, 43 full-time City of Lodi employees were assigned 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 and the IBEW recently reached an agreement on a successor Memorandum of Understanding ("MOU") with a term extending through December 31, 2017 (to succeed the prior MOU which expired on December 31, 2013). Basic terms of the new agreement include the employee paying the full employee share of retirement costs, no across-the-board pay adjustments during the term of the agreement and a cap on Lodi's payment toward medical insurance at the lowest cost HMO rate in the Lodi area. The Lodi City Council ratified this new agreement on June 18, 2014. There have been no strikes or other union work stoppages at the City of Lodi, including the electric utility department.

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 public employee defined benefit pension plan. Participants are required to contribute a percentage (7% for employees assigned to the electric utility department) of their annual covered salary. The City has historically made the contributions required of City employees on their behalf and for their account. The new MOU discussed above requires that the employees begin paying their full employee share of cost (7% of compensation) effective January 1, 2015. The City is required to contribute at an actuarially determined rate. The City of Lodi's contribution rate is determined by periodic actuarial calculations based on the benefit formula and the number of employees and their respective salary schedules. The contribution requirements of plan members and the City are established and may be amended by CalPERS. 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. For the fiscal year ended June 30, 2013, the City of Lodi's annual pension costs for the Miscellaneous Plan (which includes all electric utility employees) was $2,253,549, which was equal to the City's required contribution. Actual contributions to CalPERS funded by the electric utility for electric utility staff costs for fiscal years 2012-13 and 2011-12 were $634,053 and $601,230, respectively. Estimated contributions to CalPERS to be funded by the electric utility for electric utility staff costs for fiscal year 2013-14 are $774,100. For fiscal year 2014-15, the employer rate for the Miscellaneous plan is set at 18.002%. The City of Lodi's required contribution is determined as part of an actuarial valuation using the Entry Age Normal Actuarial Cost Method. The actuarial assumptions included (a) a 7.50% investment rate of return (net of administrative expenses), (b) projected annual salary increases that vary by age, length of service and type of employment, (c) 3.00% payroll growth and (d) 2.75% inflation. As of June 30, 2012, the most recent actuarial valuation date, the Miscellaneous Plan was 84.2% funded. The actuarial accrued liability for benefits was $146.2 million and the actuarial value of assets was $123.1 million, resulting in an unfunded actuarial accrued liability of $23.1 million. The actuarial value of CalPERS assets is determined using techniques that smooth the effects of short-term volatility in market value of investments over a fifteen-year period (smoothed market value). CalPERS unfunded actuarial accrued liability is being amortized as a level percentage of projected payroll on a closed basis. The actuarial assumptions used to determine the required contributions are the same as those used to determine the funded status. Amortization of the remaining period for the Miscellaneous Plan was 21 years as of June 30, 2012. On April 17, 2013, the CalPERS Board of Administration approved recommendations to change the amortization and smoothing rate policies. Beginning with the June 30, 2013 valuations that set the fiscal year 2015-16 rates, CalPERS will employ an amortization and smoothing policy that will pay for all gains and losses over a fixed 30-year period with the increases and decreases in the rate spread directly over a 5-year period. CalPERS, in its June 30, 2012 valuation, projected the impact of this change in amortization assumptions on employer rates. Projected rates for Lodi are 19.6% for fiscal year 2015-16, 21.2% for fiscal year 2016-17, 22.8% for fiscal year 2017-18, 24.4% for fiscal year 2018-19 and 26.1% for fiscal year 2019-20. Additionally, on February 18, 2014, the CalPERS Board of Administration approved recommendations to revise the actuarial assumptions related to the post-retirement mortality of its members. The effects of the mortality assumption changes will be incorporated into the fiscal year 2016-17 rates. Initial estimates from CalPERS indicate that rates could increase between 0.4% and 1.3% in fiscal year 2016-17. The impact of the mortality assumption changes are not reflected in the projected rates noted above. CalPERS issues a separate comprehensive annual financial report. Copies of the CalPERS annual financial report may be obtained from the CalPERS Executive Office, 400 Q Street, Sacramento, California 95814.

In addition, the City of Lodi provides certain post-employment benefits other than pensions (OPEB) to City of Lodi employees, including those assigned to the electric utility department, who retire from the City of Lodi and receive a CalPERS pension through its participation in the CalPERS medical benefits program. Contribution requirements of the OPEB benefit are based on pay-as-you-go financing. For the fiscal year 2012-13, the City of Lodi contributed $1,654,672, or 127.55% of the actuarially required contribution. The 2012-13 contribution included a one-time contribution to the OPEB fund of just under $1,000,000 (of which $105,000 was funded by the Electric Utility fund). The City of Lodi's estimated OPEB contribution for fiscal year 2013-14 is $607,000 and the budgeted amount for fiscal year 2014-15 is $804,000. The City's annual required contribution was determined as part of a January 1, 2012 actuarial valuation using the Entry Age Normal Actuarial Cost Method. The actuarial assumptions include, among others, (a) a 4.0% discount rate to calculate the present value of future benefit payments; (b) a 3.0% inflation rate; and (c) an annual healthcare cost trend rate of 9.0% initially, declining by 0.5% increments to an ultimate rate of 4.5% in the eleventh year and beyond. The actuarial methods and assumptions used include techniques that "smooth" the effects of short-term volatility in actuarial accrued liabilities and the actuarial value of assets, consistent with the long-term perspective of the calculations. The City's OPEB unfunded actuarial accrued liability is being amortized as a level percentage of expected payroll over a closed 30-year closed amortization period. As of January 1, 2012, the remaining amortization period is 27 years. As of January 1, 2012**,** the most recent actuarial valuation date, the retiree health plan has an unfunded actuarial accrued liability of $17.0 million. The portion of the plan's assets allocable to the electric utility department employees, which is part of the City of Lodi's liability pool, has not been separately calculated. The electric utility employees represent approximately 11.25% of employees of the City of Lodi. As previously noted, the City of Lodi's OPEB funding is made on a pay-as-you-go basis. The City has engaged a firm to update the actuarial report based upon a January 1, 2014 census date.

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

Service Area

Lodi is served by interstate highway 5 and State highways 12 and 99 and is located on the main line of the Southern Pacific Railroad. A deep water seaport and an airport are located approximately 15 miles south. The local economy is well-balanced among residential, agricultural, commercial and industrial sectors.

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

There are several manufacturing plants in the community area with a wide variety of products: cereals, food mixes, wines, rubber products, steel framing and industrial shelving, foundry items, recreational vehicle components, electronic substrates, and plastic piping and injection molded products. In addition, Lodi has a number of small businesses located within the City of Lodi. The main businesses in Lodi, however, are food processors and plastics.

The largest employers in Lodi as of June 30, 2013 are as follows:

CITY OF LODI
LARGEST EMPLOYERS

Employer	Business	Number of Employees
Lodi Unified School District	Education	3,650
Lodi Memorial Hospital	Health Care	1,320
Pacific Coast Producers	Fruit Canning	1,000
Blue Shield	Insurance Claims Processing	778
Cottage Bakery	Baked Goods	509
General Mills	Cereals and Food Mixes	435
City of Lodi	Government	377
Wal-Mart	Retail	230
Farmers & Merchants Bank	Banking	190
Target	Retail	160

Source: City of Lodi, City Manager's Office.

A five-year history of building permits in Lodi is as follows:

CITY OF LODI
BUILDING PERMIT VALUATION
for Calendar Years 2009 through 2013

Type of Permit	2009	2010	2011	2012	2013
Residential:					
New Single-Dwelling	$ 734,783	$ 595,647	$ 667,031	$2,627,145	$2,237,657
New Multi-Dwelling	0	0	0	0	0
Additions/Alterations	2,323,010	2,240,255	2,693,616	2,241,386	2,615,960
Total Residential	$3,057,793	$2,835,902	$3,360,647	$4,868,531	$4,853,617
Non Residential:					
New Commercial	$ 942,077	$9,982,999	$14,956,189	$ 13,870	$44,843,759
New Industrial	0	0	0	1,590,000	0
Other	1,813,849	1,959,001	3,644,527	949,818	2,229,113
Additions/Alterations	1,862,030	2,718,583	9,311,211	9,116,892	10,026,783
Total Non Residential	$4,617,956	$14,660,583	$27,911,927	$11,670,580	$57,099,655
Total Valuation	$7,675,749	$17,496,485	$31,272,574	$16,539,111	$61,953,272

Source: Construction Industry Research Board.

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

CITY OF LODI
ASSESSED VALUATIONS
For Fiscal Years 2009-10 through 2013-14
(Dollar Amounts in Thousands)

Fiscal Year	Land	Improvements	Personal Property	Total	Less Exemptions	Net Assessed Value
2009-10	$1,345,815	$3,600,824	$312,792	$5,259,431	$332,701	$4,926,730
2010-11	1,322,830	3,534,778	323,003	5,180,611	321,138	4,859,473
2011-12	1,264,884	3,401,792	301,180	4,967,856	314,448	4,653,408
2012-13	1,227,969	3,445,328	300,290	4,973,587	327,783	4,645,804
2013-14	1,186,218	3,328,187	290,080	4,804,485	316,638	4,487,847

Source: City of Lodi.

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
(1970–2010 as of April 1; 2011-2014 as of January 1)

	City of Lodi	County of San Joaquin	State of California
1970	28,691	291,073	19,971,069
1980	34,850	343,500	23,668,562
1990	51,900	477,700	29,760,021
2000	57,011	563,598	33,873,086
2010	62,134	685,306	37,253,956
2011	62,344	689,160	37,427,946
2012	62,575	693,013	37,668,804
2013	63,233	701,745	37,984,138
2014	63,651	710,731	38,340,074

Source: U.S. Bureau of Census and California State Department of Finance.

Litigation

There is no action, suit or proceeding known to be pending or threatened, restraining or enjoining Lodi in the execution or delivery 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.

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 2012-13 average rate per kWh for residential service was $0.1672 cents. Lodi's fiscal year 2012-13 average rate for commercial and industrial service was $0.1333 cents per kWh. Lodi's fiscal year 2013-14 average rate per kWh for residential service is projected to be $0.1710 cents. Lodi's fiscal year 2013-14 average rate for commercial and industrial service is projected to be $0.1345 cents per kWh.

The following table presents a recent history of Lodi's rate increases since 2005. The last base rate increase was in December 2005.

CITY OF LODI
ELECTRIC UTILITY DEPARTMENT
RATE CHANGES

Effective Date	Percent Change
July 2013	Established Electric Vehicle and Industrial Equipment Charge Rates
April 2009	Established Economic Development Rates updated July 2013
December 2007	Established Solar Initiative Surcharge of $0.00125 per kilowatt-hour
August 2007	Implemented monthly Energy Cost Adjustment
December 2005	Average 17% increase across all rate classes

Source: City of Lodi.

Lodi has engaged a consultant to develop a rate model and cost of services study. Staff presented the rate model to the City Council in August 2014. Council directed staff to return with an ordinance that proposes a rate increase in October 2014. Staff will be recommending an across-the-board rate increase of 5% with following annual rate increases of the lesser of CPI or 2%.

The Lodi City Council reviews electric system rates periodically and makes adjustments as necessary. The City has adopted a number of rate policies which apply to contract rates with certain customers. See "Lodi's Operations Since Industry Restructuring" herein.

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. The ECA is reviewed monthly and is either increased or decreased as market conditions dictate. The historic, average ECA is listed below.

CITY OF LODI
ENERGY COST ADJUSTMENTS
For Fiscal Years 2008-09 through 2012-13

Fiscal Year	ECA
2008-09	$0.0157
2009-10	0.0137
2010-11	0.0087
2011-12	0.0014
2012-13	0.0085

Largest Customers

The ten largest customers of Lodi's electric system in terms of kWh sales, as of June 30, 2013, accounted for 28.6% of total kWh sales and 22.5% of revenues. The largest customer accounted for 5.8% of total kWh sales and 4.1% of total revenues.

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 "DEVELOPMENTS IN THE CALIFORNIA ENERGY MARKETS" and "OTHER FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY" in the front part of this Remarketing Memorandum. These actions include:

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

- **The Risk Management Program**. City established an Energy Risk Management Policy. Consistent with the policy Lodi has established goals related to closing open power positions in the current, next and second following fiscal year to provide for orderly stabilization of future power costs.

Timeframe	Open Position
Current Fiscal Year	10%
Next Fiscal Year	25%
2nd Fiscal Year	50%

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).

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 2008-09 through 2012-13, are listed below.

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

	Fiscal Years Ended June 30,				
	2009	**2010**	**2011**	**2012**	**2013**
Number of Customers:					
Residential	22,465	21,981	22,251	22,244	22,369
Commercial	2,696	3,194	2,865	2,834	2,902
Industrial	37	31	39	37	39
Other	188	194	229	235	246
Total	25,386	25,369	25,384	25,350	25,556
Kilowatt Hour (kWh) Sales:					
Residential	153,487,430	150,811,587	144,256,683	149,814,375	151,814,834
Commercial	155,206,324	146,644,990	137,584,723	138,735,487	140,733,500
Industrial	131,059,764	125,000,860	128,072,575	135,620,441	131,473,405
Other	12,322,036	11,563,550	11,216,348	11,485,428	11,800,726
Total	452,075,554	434,020,987[(3)]	421,130,329[(3)]	435,655,731	435,822,465
Revenues from Sale of Energy [(2)]					
Residential	$29,016,777	$27,642,200	$24,513,202	$25,606,368	$25,377,978
Commercial	26,883,557	24,901,257	21,870,624	21,814,073	21,816,149
Industrial	15,875,038	15,015,036	13,914,539	14,876,828	14,173,951
Other	2,224,567	2,105,196	1,868,985	1,954,099	1,861,567
Total	$73,999,939	$69,663,689	$62,167,350	$64,251,368	$63,229,645
Peak Demand (kW)	117.4	119.6	123.9	116.0	123.3

(1) Columns may not add to totals due to rounding.
(2) Excludes revenues from California Energy Commission Tax.
(3) Decline in kWh sales primarily due to mild weather, increased customer participation in energy efficiency and solar programs and general weaker economic conditions.
Sources: City of Lodi, comprehensive annual financial statements and Customer Information System reports.

Indebtedness; Joint Powers Agency Obligations

As of June 30, 2014, Lodi had outstanding $70.8 million principal amount of obligations (including accreted value of capital appreciation certificates) 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. Lodi has no variable rate or auction rate direct debt.

As previously discussed, Lodi participates in certain joint powers agencies, including NCPA and TANC. 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 the 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 June 30, 2014)

	Outstanding Debt[1]	Lodi's Participation[2]	Lodi's Share of Outstanding Debt[1]
NCPA			
Geothermal Project	$ 41.3	10.28%	$ 4.2
Hydroelectric Project	401.2	10.37[3]	42.7
Capital Facilities Project	48.1	39.50	19.0
Lodi Energy Center, Issue One	245.7	17.03	41.8
TANC			
COTP	314.2	1.92[4]	6.0
TOTAL	$1,050.5		$113.7

(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 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) As described herein, Lodi's actual payment 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. As described herein, effective July 1, 2014, Lodi has entered into a layoff with Roseville for 25 years of its COTP interest which will effectively reduce Lodi's share of outstanding debt to $0. Lodi remains contractually obligated for its share. See "Power Supply Resources–Joint Powers Agency Resources–*TANC California-Oregon Transmission Project*."

Source: City of Lodi.

Lodi estimates its payment obligations for debt service on its joint powers agency debt obligations aggregated approximately $10.6 million for the fiscal year ended June 30, 2013 and will aggregate approximately $9.7 million for the fiscal year ending June 30, 2014. It should be noted that the June 30, 2014 amount does not include any COTP amount as Lodi's share of the debt will be 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. In connection with certain of such joint power agency obligations, the respective joint powers agency has entered into interest rate swap agreements relating thereto for the purposes of substantially fixing the interest cost with respect thereto. There is no guarantee that the floating rate payable to the respective joint powers agency pursuant to each of the interest rate swap agreements relating thereto 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 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 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 Lodi).

Significant Accounting Policies

Lodi's most recent Annual Financial Report for the fiscal year ended June 30, 2013 was audited by Macias, Gini & O'Connell, LLP, Sacramento, 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, 221 West Pine Street, Lodi, California 95240. 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 2008-09 through 2012-13. The information for the fiscal years ended June 30, 2009 through June 30, 2013 was prepared by Lodi on the basis of its audited financial statements for such years.

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

	Fiscal Year ended June 30,				
OPERATING REVENUES	**2009**	**2010**	**2011**	**2012**	**2013**
Rate Revenue	$65,229	$62,613	$59,676	$61,658	$61,888
ECA Revenue	8,771	7,050	2,491	2,593	1,341
Other Revenue	1,195	625	1,140	969	745
Total Operating Revenues	$75,195	$70,288	$63,307	$65,220	$63,974
OPERATING EXPENSES					
Purchased Power	$46,405	$37,943	$35,282	$39,416	$39,191
Non-Power Costs	11,965	12,006	13,115	10,748	12,018
Total Operating Expenses	$58,370	$49,949	$48,397	$50,164	$51,209
NET REVENUE	$16,825	$20,339	$14,910	$15,056	$12,765
Debt Service	9,960	7,194	7,232	7,291	8,414
Remaining After Debt Service	$ 6,865	$ 13,145	$ 7,678	$ 7,765	$ 4,351
OTHER REVENUES (EXPENSES)					
Greenhouse gas allowance[3]	--	--	--	--	2,018
Payments in Lieu of Taxes	(6,942)	(6,977)	(6,977)	(6,977)	(6,977)
Net Cash Flow Before Capital Expenditure	$ (77)	$ 6,168	$ 701	$ 788	$ (608)
SELECTED BALANCE SHEET INFORMATION:					
Net Plant in Service	$37,386	$37,044	$36,067	$43,673	$43,976
Land and Construction Work in Progress	$ 6,418	$ 6,213	$ 6,464	$0	$0
Ending Operating Reserve Balance	$13,854	$25,899	$28,454	$30,384	$31,082
Long-Term Debt	$83,234	$80,525	$77,656	$74,630	$70,331
Debt Service Coverage Ratio[1]	1.69	2.83	2.06	2.07	1.52

(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 Generally Accepted Accounting Principles. See "Indebtedness; Joint Powers Agency Obligations."
(2) Non-power costs include costs of services provided by other departments and does not include depreciation and amortization expense.
(3) Revenues associated with cap-and-trade program.
Source: City of Lodi.

CITY OF PALO ALTO

Introduction

The City of Palo Alto ("Palo Alto" or the "City") is a charter city of the State of California. Pursuant to its charter, 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 legal responsibilities and power of the Department of Utilities, including the establishment of rates and charges, are exercised through the nine-member Palo Alto City Council. The members of the City Council are elected city-wide for staggered four-year terms. The Palo Alto Department of Utilities is under the direction of the Director 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, 2013, Palo Alto served 29,474 customers, had total sales of approximately 977 million kWh and a peak demand of 174 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 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.

Palo Alto has a comprehensive Energy Risk Management Program governing electric and natural gas transactions. The program consists of City Council approved policies, and operational guidelines approved by the Risk Oversight and Coordination Committee. The program segregates 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 Valerie Fong**,** Director of Utilities, at the above address and telephone number. A copy of the most recent comprehensive annual financial report of the City of Palo Alto (the "Annual Report") is available on Palo Alto's website at *http://www.cityofpaloalto.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 Remarketing Memorandum and is not incorporated by reference herein.

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, 2013.

CITY OF PALO ALTO
DEPARTMENT OF UTILITIES
POWER SUPPLY RESOURCES
For the Fiscal Year Ended June 30, 2013

Source	Capacity Available (MW)	Actual Energy (GWh)	Percent of Total Energy
Purchased Power:			
Western	161	364.6	37%
Wind Energy	45	114.4	12
Landfill Gas Energy	14	68.7	7
Forward Market Purchases(1)	95(3)	331.5	34
NCPA			
Geothermal Project(2)	--	--	--
Hydroelectric Project	57	57.9	6
Seattle City Light Exchange(4)	--	--	--
Short-Term Market	--	39.5	4
Total	N/A(5)	976.6	100%
System Requirement for Retail	195		

(1) See "–Purchased Power–Other Power Purchases" below.
(2) Capacity and energy sold to TID. See "–Joint Powers Agency Resources–NCPA" below.
(3) Forward Market Purchase capacity not applicable to system or local reliability requirements.
(4) Assigned to City of Santa Clara effective June 2008. See "–Joint Powers Agency Resources–NCPA" below.
(5) 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, 2013, Palo Alto's average cost of power delivered to the Palo Alto electric system was approximately 6.1 cents per kWh.

Purchased Power

Western. Palo Alto receives a substantial portion of its supply of power from the 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 the new 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 will increase 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 (11.620%, increasing to 12.309% on January 1, 2015) of the costs associated with operating the CVP facilities. Palo Alto's energy allocation dropped from the prior levels of approximately 900 GWh/year prior to 2005, to about 380 GWh/year in an average hydrological year starting in January 2005. Palo Alto's annual cost obligation under the Western Base Resource Contract is approximately $12 million per year, resulting in an average cost of approximately $33 per MWh in an average hydrological year.

Wind Energy Contracts. Palo Alto currently has two long-term contracts for the output of wind electricity generation. Under a contract with Iberdrola Renewables (formerly PPM Energy, Inc.), 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 52

GWh/year. The term of such contract ends in 2028. Under a separate contract with Iberdrola Renewables (formerly PPM Energy, Inc.), for power from the Shiloh I project (owned by Iberdrola Renewables) in Solano County, Palo Alto is allocated available capacity of 25 MW and acquired a fixed unit price on expected generation of 74.8 GWh/year. The term of such contract ends in 2021.

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 9.9 GWh/year. The Santa Cruz project began commercial operation in February 2006. The term of such contract 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 43.9 GWh/year. The Ox Mountain project began commercial operation in April 2009. The term of such contract 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 14.9 GWh/year. The Keller Canyon project began commercial operation in August 2009. The term of such contract 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 10.4 GWh/year. The Johnson Canyon project began commercial operation in May 2013. The term of such contract 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 30.3 GWh/year. The San Joaquin project began commercial operation in April 2014. The term of such contract ends in 2034.

Palo Alto expects to receive a total of 109 GWh 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.

Other Power Purchases. Palo Alto has nine active Master Agreements with BP Energy, Shell Energy North America, Powerex Corp, Cargill Power Markets, Exelon Generation, Iberdrola Renewables, NextEra Energy Power Marketing, Turlock Irrigation District, and PacifiCorp to facilitate competitive forward market purchases to meet Palo Alto's loads in the short- to medium-term. As of June 30, 2013, Palo Alto had outstanding electricity purchase commitments for the period July 2013 to June 2017 totaling 291 GWh. These market based purchases are made within the parameters of Palo Alto's Energy Risk Management Program.

In fiscal year 2012-13, market based purchases represented approximately 38% of Palo Alto's energy needs. The volume of market purchases however is highly dependent on hydro conditions and long-term commitments to renewable resource based supplies. During normal hydro conditions, market purchases are expected to meet approximately 25% of energy needs and will reduce to less than 10% as renewable energy targets are met. 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 Remarketing Memorandum.

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 several NCPA projects. Palo Alto has purchased from NCPA a 22.920% entitlement share in the NCPA Hydroelectric Project. Palo Alto has purchased from NCPA a 6.158% participation in the NCPA Geothermal Project. Palo Alto has sold its share of the Geothermal Project to Turlock Irrigation District ("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 the payment of project costs to the extent 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, 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 addition, in 1992, NCPA entered into an agreement with Seattle City Light to provide for a seasonal power exchange. The agreement entitles Palo Alto to 11 MW (10.3 MW at Palo Alto meter) during the summer and obligates it to return 8 MW (at Palo Alto meter) during the winter. Deliveries under this agreement began June 1, 1995. NCPA has provided notice to Seattle City Light to terminate this agreement effective in 2018. Changes in Palo Alto's electric portfolio needs and wholesale market conditions led Palo Alto to assign its full share and obligations in the Seattle City Light exchange to the City of Santa Clara effective June 2008.

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

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. For a further description of the TANC COTP project, see "CITY OF ALAMEDA—Joint Powers Agency—*TANC California-Oregon Transmission Project*" herein.

Future Power Supply Resources

In accordance with LEAP, Palo Alto has entered into a number of electricity purchase contracts as described above. As of June 30, 2014, Palo Alto had procured approximately 83.65% of its total projected electricity needs for fiscal year 2014-15 (assuming the projected hydroelectric production). Additional renewable generation contracts are expected to be in place to meet Palo Alto's energy needs.

Palo Alto's current renewable energy resource policy targets a 33% resource portfolio share by 2015. 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 customers to voluntarily participate in a green power program whereby participating customers pay renewable energy retail rates. Palo Alto's customer participation rate in such programs was the highest for all similar programs in the United States, as determined by the U.S. Department of Energy National Renewable Energy Laboratory.

In July 2006, Palo Alto entered into an agreement with NCPA relating to the NCPA Green Power Project ("NGPP") to facilitate the joint purchase of renewable energy resources on behalf of eleven participating NCPA members. No additional contracts will be negotiated as part of the NGPP on behalf of Palo Alto.

Palo Alto is also evaluating local cogeneration opportunities at customer sites and solar photovoltaic projects within Palo Alto. Palo Alto continues 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.

Carbon Neutral Plan. In March 2013 the Palo Alto City Council approved a Carbon Neutral Electric Resource Plan committing Palo Alto to using carbon neutral electric resources beginning in calendar year 2013. The policy 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). By 2017, Palo Alto expects its hydroelectric and renewable generation contracts to provide enough energy to supply its entire load (assuming average hydroelectric conditions). In the near-term (or in the event of dry hydroelectric conditions), Palo Alto plans to continue to make short-term market electricity purchases, supplemented with the purchase of renewable energy certificates (RECs) to achieve carbon neutrality.

Local Solar Plan. In April 2014, the Palo Alto City Council passed the Local Solar Plan, which sets the City-wide goal of meeting 4% of the City's energy needs from local solar by 2023 (up from 0.7% in 2013) and identifies a number of strategies to facilitate achieving that goal including the development of several solar programs to encourage installation of roof-top solar as funding for the City's PV Partners program and other incentives are fully disbursed.

Energy Efficiency and Conservation

Palo Alto's Electric and Gas Public Benefits and Water Efficiency Programs include efficiency; renewable energy; low-income 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, it 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. The LEAP includes energy efficiency as the highest-priority goal and requires that an assessment of least total cost, which includes environmental costs and benefits, be conducted when acquiring any energy resource. 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 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 California Energy Commission (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 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 10-year cumulative savings goal of 3.5% of the forecasted energy use. In accordance to 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. An updated set of Ten-Year Electric Efficiency Goals, adopted by City Council in December 2012, revised the ten-year cumulative electric efficiency savings to 4.8% between 2014 and 2023. Since 2008, Palo Alto has met or exceeded its annual electric efficiency goals. For the fiscal year 2012-13, the electric utility achieved electric savings of 0.85% of load through its customer efficiency programs. Cumulative electric efficiency savings since 2006 is about 5.2% of the fiscal year 2013 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 most recent set of gas efficiency goals was last updated in December 2012, with a ten-year cumulative gas efficiency target of 2.85% between 2014 and 2023. For fiscal year 2012-2013, the gas utility achieved gas savings of 1.13% of load. Cumulative gas efficiency savings since 2006 is about 2.9% of the fiscal year 2013 gas usage.

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. As of June 30, 2014, there were 654 PV installations with the total capacity of 5.59 MW (3.2% of Palo Alto's system peak load).

Palo Alto CLEAN (Clean Local Energy Accessible Now): This feed-in tariff program purchases electricity generated by solar photovoltaic (PV) systems 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 the electric renewable portfolio standard. 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. 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 is working with the City's Public Works Department to solicit proposals to install solar PV on five City-owned parking structures. As of June 30, 2014 there have been no applications.

Solar Hot Water Program: Palo Alto launched the solar water heating (SWH) program in May 2008, in advance of a State law requiring natural gas utilities to offer incentives. This program offers rebates of up to $2,719 for residential systems and up to $100,000 for commercial and industrial systems. A sample of installations are inspected for quality and program compliance by an independent contractor. A total of 43 systems have been installed as of June 30, 2014; 41 of these are residential. The rebates paid totaled $133,604 and resulted in annual savings of 8,773 therms and 13,387 kWh.

As required by state law (AB 2021), publicly owned utilities are required to conduct an independent evaluation that measures and verifies the energy efficiency savings and reduction in energy demand achieved by its energy efficiency programs.

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 very 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.
- ***ProjectPLEDGE.*** 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.

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.

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

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,				
2015	2016	2017	2018	2019
$4,067	$4,185	$4,306	$4,421	$4,541

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.

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.

Employees

As of June 1, 2014, 114.26 full-time equivalent ("FTE") staff were assigned to the electric system of the Palo Alto Department of Utilities. All full-time employees, excluding those in management, confidential and professional classifications, are represented by the 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. The memorandum of understanding with this union expires on December 1, 2015. Management employees receive substantially the same fringe benefit package as the SEIU members, and are represented by the Utilities Management and Professional Association of Palo Alto ("UMPAPA"). The current memorandum of understanding between the City and UMPAPA expires on December 31, 2014. Palo Alto's wage and fringe benefits are generally comparable to those offered by other local public agencies.

Palo Alto covers substantially all of its permanent employees under pension plans offered by the California Public Employees Retirement System ("CalPERS"), an agent for multiple employer defined benefit pension plan, which acts as a common investment and administrative agent for its participating member employers. Pension costs are funded by monthly contributions to CalPERS by Palo Alto. Employees of the City of Palo Alto Department of Utilities participate in the Miscellaneous Plan, which is part of the Public Agency portions of CalPERS (the "Plan"). CalPERS determines contribution requirements using a modification of the Entry Age Normal Method. Under this method, the City's total normal benefit cost for each employee from date of hire to date of retirement is expressed as a level percentage of the related payroll cost. Normal benefit cost under this method is the level amount the employer must pay annually to fund an employee's projected retirement benefit. This level percentage of payroll method is used to amortize any unfunded actuarial liabilities. The actuarial assumptions used to compute contribution requirements are also used to compute the actuarial accrued liability. The City uses the actuarially determined percentages of payroll to calculate and pay contributions to CalPERS.

CalPERs uses the 15-year smoothed market method of valuing Plan assets. An investment rate of return of 7.50% is assumed, including inflation at 2.75%. Annual salary increases are assumed to vary by duration of service. Changes in liability due to plan amendments, changes in actuarial assumptions, or changes in actuarial methods are amortized as a level percentage of payroll on a closed basis over 20 years. Investment gains and losses are tracked and amortized over a 30-year rolling period, except for special gains and losses in fiscal years 2009 through 2011 which are being amortized over fixed and declining 30 year periods. CalPERS issues a separate comprehensive annual financial report. Copies of the CalPERS annual financial report may be obtained from the CalPERS Executive Office, 400 Q Street, Sacramento, California 95814.

The City of Palo Alto's Annual Pension Cost, representing the payment of annual required contributions determined by CalPERS for the Miscellaneous Plan for the three fiscal years 2010-11 through 2012-13 were as follows: fiscal year 2010-11, $12,354,000; fiscal year 2011-12, $15,687,000; and fiscal year 2012-13, $15,801,000. The City of Palo Alto made these contributions as required. At June 30, 2012 (the most recent actuarial information available), the actuarial accrued liability for all City of Palo Alto employees under the Miscellaneous Plan was approximately $576,182,013, the actuarial value of assets (which differs from market value) was approximately $447,819,353 and the actuarial accrued unfunded liability was approximately $128,362,660, representing a funded ratio of 77.7%.

On April 17, 2013 the CalPERS Board of Administration approved new actuarial policies aimed at fully funding the pension system's obligations within 30 years. The new policies include a rate-smoothing method with a 30-year fixed amortization period for gains and losses. CalPERS announced that, based on investment return simulations performed for the next 30 years, increasing contributions more rapidly in the short term is expected to result in almost a 25% improvement in funded status over a 30-year-period. The new amortization schedule will be used to set contribution rates for public agency employers in the State beginning in the 2015-16 fiscal year. This delay is intended to allow the impact of the changes to be built into the projection of employer contribution rates and afford employers with additional time to adjust to the changes.

According to CalPERS, the new policies will result in an increased likelihood of higher peak employer contribution levels in the future but will not significantly increase average contribution levels. The median employer contribution rate over the next four years is expected to be higher. In the long-term, however, higher funded levels may result in lower employer contributions.

On February 20, 2014, the CalPERS Board of Administration adopted new mortality and retirement assumptions as part of a regular review of demographic experience. Key assumption changes included longer post-retirement life expectancy and earlier retirement ages. The impact of the assumption changes will be phased in over five years, with a twenty-year amortization, beginning in the 2016-17 fiscal year. CalPERS has estimated that the adoption of the new assumptions will increase employer contribution rates (as a percentage of payroll) for most Miscellaneous Plans in the range of by 0.4% to 1.9% in the 2016-17 fiscal year and in the range of by 1.0% to 6.7% by 2020-21, depending on the benefit formula applicable to active members.

In addition to providing pension benefits, the City of 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 City of Palo Alto Department of Utilities. 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. In fiscal year 2007-08, Palo Alto implemented the provisions of Governmental Accounting Standards Board Statement No. 45, Accounting and Financial Reporting for Postemployment Benefits Other Than Pensions ("OPEB"), and elected to participate in an irrevocable trust to provide a funding mechanism for its OPEB liability. The trust, California Employers' Retirees Benefit Trust ("CERBT"), is administered by CalPERS and managed by a separately appointed board, which is not under control of the City Council. The City's policy is to prefund these OPEB benefits by accumulating assets in the Trust Fund pursuant to City Council Resolution. The annual required contribution ("ARC") was determined as part of a January 1, 2011 actuarial valuation using the entry age normal actuarial cost method, which takes into account those benefits that are expected to be earned in the future as well as those already accrued. The actuarial assumptions include: (i) a 7.75% investment rate of return, (ii) a 3.25% projected annual salary increase, and (iii) specified health care cost trends declining to 5.00% in 2021 and beyond. The actuarial methods and assumptions used include techniques that smooth the effects of short-term volatility in actuarial accrued liabilities and the actuarial value of assets. The City of Palo Alto's OPEB unfunded actuarial accrued liability is being amortized as a level percentage of projected payroll using a 30-year open amortization period.

The Plan's annual OPEB Cost and the City's actual contributions for the three fiscal years 2010-11 through 2012-13 were as follows: fiscal year 2010-11, Annual OPEB Cost, $10,265,000, City Actual Contribution, $10,029,000; fiscal year 2011-12, Annual OPEB Cost, $13,058,000, City Actual Contribution, $11,323,000; and fiscal year 2012-13, Annual OPEB Cost, $13,194,000, City Actual Contribution, $13,774,000. The Annual OPEB cost is equal to the employer's annual required contribution to the plan (ARC), with certain adjustments if the employer has a net OPEB obligation for past under- or over-contributions As of June 30, 2013, the most recent actuarial valuation date, the City of Palo Alto's retiree health (OPEB) plan had an entry age actuarial accrued liability for all City of Palo Alto employees of approximately $203,642,000, the actuarial value of assets (which differs from market value) was approximately $60,070,000 and the actuarial accrued unfunded liability was approximately $143,572,000, representing a funded ratio of 29%.

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

Service Area

The main businesses in Palo Alto are manufacturing and industrial. 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, 2013 are shown in the following table.

CITY OF PALO ALTO
LARGEST EMPLOYERS

Employer	Business	Number of Employees
Stanford University	Education	10,979
Stanford University Medical Center/Hospital	Hospital	5,545
Lucille Packard Children's Hospital	Health Care Delivery	4,750
Veteran's Affairs Palo Alto Health Care System	Health Care Delivery	3,850
VMware Inc.	Software	3,509
Space Systems Loral	Satellite System Design & Manufacturing	3,020
Hewlett Packard Company	Computer Hardware and Software	2,500
Palo Alto Medical Foundation	Health Care Delivery	2,200
SAP	Software	2,200
Wilson Sonsini Goodrich Rosati	Legal Services	1,650

Source: City of Palo Alto.

A five-year history of building permits in Palo Alto is as follows:

CITY OF PALO ALTO
BUILDING PERMITS
For Calendar Years 2009-2013

	2009	2010	2011	2012	2013
Residential Valuation (in thousands)					
Single Family	$30,683	$50,946	$37,535	$51,154	$44,914
Multifamily	7,306	5,000	1,278	3,193	17,244
TOTAL	$37,989	$55,946	$38,813	$54,347	$62,158
New Dwelling Units					
Single Family	58	144	78	89	81
Multiple Family	27	35	4	18	100
TOTAL	85	179	82	107	181

Sources: Construction Industry Research Board.

Shown below is certain population data for Palo Alto, the County of Santa Clara and the State of California:

CITY OF PALO ALTO, COUNTY OF SANTA CLARA,
STATE OF CALIFORNIA POPULATION
(1970-2010 as of April 1; 2011-2014 as of January 1)

Year	City of Palo Alto	County of Santa Clara	State of California
1970	55,835	1,065,313	19,971,069
1980	55,200	1,295,071	23,668,562
1990	57,400	1,497,577	29,760,021
2000	58,917	1,682,585	33,873,086
2010	64,403	1,781,642	37,253,956
2011	64,853	1,794,337	37,427,946
2012	65,443	1,813,702	37,668,804
2013	66,318	1,840,895	37,984,138
2014	66,861	1,868,558	38,340,074

Sources: U.S. Bureau of Census and California State Department of Finance.

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.

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

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 Remarketing

Memorandum, 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.

Lawsuits and other claims filed against Palo Alto as it relates to its Department of Utilities' electric utility 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 or the Department of Utilities electric utility system and operations.

Rates and Charges

The Palo Alto City Council is authorized by the Palo Alto Municipal Code 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 are adopted by the City Council. These rates are not subject to review by any State or federal agency.

The Municipal Code also provides that the City Council shall 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 Palo Alto. 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 costs and expenses of such utility.

Palo Alto's fiscal year 2012-13 average rates per kWh for residential service was 12.2 cents. Palo Alto's fiscal year 2012-13 average rates for commercial and industrial service was 11.4 cents per kWh. Palo Alto's fiscal year 2013-14 average rate per kWh for residential service was 11.7 cents. Palo Alto's fiscal year 2013-14 average rate for commercial and industrial service was 11.6 cents per kWh.

The following table presents a history of Palo Alto's electric utility rate increases since 2009. There are no planned rate increases for fiscal year 2014-15.

CITY OF PALO ALTO
DEPARTMENT OF UTILITIES
RATE CHANGES

Date	Percent Change
July 1, 2013	0.0%
July 1, 2012	0.0
July 1, 2011	0.0
July 1, 2010	0.0
July 1, 2009	10.0

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.

Largest Customers

The ten largest customers of Palo Alto's electric utility system, based upon energy usage for the fiscal year ended June 30, 2013 accounted for approximately 39.4% of total kWh sales and approximately 35.4% of total electric revenues. The largest account consumed 8.2% of Palo Alto's total kWh sales and contributed 7.2% of total revenues and the smallest of the ten largest accounts accounted for 1.8% of total kWh sales and 1.6% of revenues.

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.

Calaveras–Stranded Costs 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.

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 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").

In 1996, the City Council changed the purpose of the Calaveras Reserve and authorized collections from electric ratepayers to cover its stranded cost. In addition, the City Council approved a new Calaveras Reserve policy linking the reserve balance to an amount sufficient to cover potential stranded costs. The assets identified as stranded included the Seattle City Light Exchange contract, 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 approved a new policy direction regarding the management of the Calaveras Reserve along with new guidelines as follows:

- Change the purpose of the Calaveras Reserve from partially funding above market electric costs and partially funding projects that benefit electric ratepayers to entirely funding projects that benefit electric ratepayers;
- Rename the Calaveras Reserve as the Electric Special Project (ESP) Reserve; and
- Adopt the following ESP Reserve guidelines:
  - 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 value to electric ratepayers. The projects must have verifiable value and not be speculative, or be high risk in nature;
  - Projects proposed for funding must be substantial in size, requiring funding of at least $1 million;
  - A goal is to identify preferred projects for funding from the ESP Reserve by end of fiscal year 2015; and
  - Any uncommitted funds remaining at the end of fiscal year 2020 will be transferred to the Electric Supply Rate Stabilization Reserve and the ESP Reserve will be closed.
  - Funds may be used for analysis and pilot projects which would be the basis for planned large projects.
- Staff will identify a process and criteria for identifying eligible projects.

The approximate balance of the Calaveras Reserve (since renamed the ESP Reserve as described above) for the five fiscal years 2008-09 through 2012-13 (in thousands of dollars) is set forth below:

	2008-09	2009-10	2010-11	2011-12	2012-13
Balance	$64,535	$59,865	$55,558	$50,320	$51,838

Source: For fiscal years 2008-09 through 2012-13 City of Palo Alto Audited Financial Statements.

As of June 30, 2014, the balance of Calaveras Reserve is $51,837,855.

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 Rate Stabilization Reserves 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 new Western Base Resource Contract. As of June 30, 2013, the balance of RSR was $69.0 million. The RSR is separate from the Calaveras Reserve.

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, 2013 was $2.2 million.

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 are 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. The distribution charge, transition cost recovery charge and public benefits charge are nonbypassable charges and therefore are paid to Palo Alto by the customer, regardless of energy supplier. On July 1, 1999, the transition cost recovery charge was discontinued.

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 2008-09 through 2012-13, are listed below.

CITY OF PALO ALTO
DEPARTMENT OF UTILITIES
CUSTOMERS, SALES, REVENUES AND DEMAND[(1)]

	2009	2010	2011	2012	2013
Number of Customers[(2)]:					
Residential	25,691	26,583	26,793	26,713	26,642
Commercial	2,431	2,439	2,488	2,449	2,482
Industrial	193	188	178	150	131
Other	212	220	225	215	219
Total	28,527	29,430	29,684	29,527	29,474
Kilowatt-Hour Sales (in thousands):					
Residential	192,109	196,286	193,236	191,636	186,997
Commercial	404,784	402,219	411,621	428,810	448,922
Industrial	309,716	284,568	258,613	236,814	227,431
Other	89,073	82,016	83,047	85,304	83,490
Total	995,682	965,089[(3)]	946,517[(3)]	942,564	946,841
Revenues from Sale of Energy:					
Residential	$ 21,984	$ 24,719	$ 24,391	$ 20,328	$ 19,951
Commercial	43,197	47,645	49,256	60,443	62,671
Industrial	31,233	31,192	28,977	25,452	24,327
Other	8,798	9,020	9,384	3,352	3,265
Total	$105,212	$112,576	$112,008	$109,575	$110,214
Peak Demand (MW)	195.0	186.5	186.2		

(1) Columns may not add to totals due to rounding.
(2) Revenues are exclusive of wholesale sales.
(3) Decline in demand primarily due to slowing of the economy, milder weather and investment in energy efficient technologies by the electric utility customers.

Source: City of Palo Alto.

Indebtedness; Joint Powers Agency Obligations

In October 2007, the City issued $1.5 million of 2007 Electric Utility Clean Renewable Energy Tax Credit Bonds ("CREBs") to finance the City'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, 2014, the remaining outstanding principal balance of the CREBs was $0.8 million.

The City issued Utility Revenue Bonds, 1995 Series A (the "1995 Utility Bonds") on February 1, 1995 to finance certain extensions and improvements to the City's Storm Drainage and Surface Water System. The 1995 Utility Bonds are special obligations of the City secured by a lien on net revenues of the City's entire "Enterprise," which consists of the City of Palo Alto water system, gas system, storm and surface water drainage system, sanitary sewer system, and electric utility system. The annual principal and interest debt service payments are solely paid by the City's storm and surface water drainage system. As of June 30, 2014, the outstanding principal amount of the 1995 Utility Bonds was $3.3 million.

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 Palo Alto 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 June 30, 2014)

	Outstanding Debt(1)	Palo Alto Participation(2)	Palo Alto Share of Outstanding Debt(1)
NCPA			
Geothermal Project	$ 41.3	0.0%(3)	$ 0.0(3)
Hydroelectric Project	401.2	22.92(4)	94.4(4)
TANC			
Bonds	$314.2	0.0(5)	0.0(5)
TOTAL	$756.7		$94.4

(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) Participant share of 6.16% was sold to TID in October 1984. Palo Alto remains contractually liable for its share. See "Power Supply Resources–Joint Powers Agency Resources–*NCPA*."
(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*."

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. In connection with certain of such joint power agency obligations, the respective joint powers agency has entered into interest rate swap agreements relating thereto for the purposes of substantially fixing the interest cost with respect thereto. There is no guarantee that the floating rate payable to the respective joint powers agency pursuant to each of the interest rate swap agreements relating thereto 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 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 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 Palo Alto).

Significant Accounting Policies

Palo Alto's most recent Annual Financial Report for the fiscal year ended June 30, 2013 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. 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 Department of Utilities electric utility system for the five fiscal years 2008-09 through 2012-13. The information for the fiscal years ended June 30, 2009 through June 30, 2013 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
CONDENSED OPERATING RESULTS AND SELECTED BALANCE SHEET INFORMATION[(1)]
(Dollar Amounts in Thousands)

	Fiscal Year ended June 30,				
	2009	**2010**	**2011**	**2012**	**2013**
Summary of Income:					
Operating Revenues	$122,656	$125,005	$122,109	$118,886	$121,805
Operating Expenses[(2)]	(121,865)	(110,667)	(93,257)	(93,184)	(97,076)
Other Income	8,172	6,238	(4,042)	(4,703)	(10,666)
Loss on Disposal of Fixed Assets	(1,069)	(173)	(49)	(180)	(395)
Transfers in	33	3,025	550	103	296
Transfers out[(3)]	(12,700)	(11,918)	(12,206)	(11,886)	(12,090)
Net Income	$(4,773)[(4)]	$ 11,510	$13,105	$9,036	$1,874
Selected Balance Sheet Information:					
Net Property Plant and Equipment	$159,136	$164,484	$161,699	$166,085	$171,933
Unrestricted	137,411	143,573	142,653	147,303	143,329
Total Net Assets	$296,547	$308,057	$304,352	$313,388	$315,262

(1) Includes electric and fiber optics funds.
(2) Includes purchased power costs and payments to NCPA and TANC. Also includes depreciation.
(3) 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.
(4) Net loss of $4.8 million due to an $11.3 million increase in purchased power costs due to unfavorable hydrologic conditions. This was an anticipated cost increase which was managed by a combination of a 14.1% retail rate increase and a drawdown of $7.6 million from Rate Stabilization Reserves.

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. The City, with a population estimated to be approximately 126,956 at January 1, 2014, is the largest city in Placer County, as well as the residential and industrial center of the County.

The City, 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 69 megawatts ("MW"; a megawatt equals 1 million watts) of electric capacity from the Central Valley hydroelectric project, which consists of a system of dams, reservoirs and 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. 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 in the NCPA Combustion Turbine Project No. 1 (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," to meet reserve and capacity requirements (referred to herein as "Roseville Power Plant 2").

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 Public Utilities Commission. The Electric Utility Director oversees operations of the utility and reports to the Commission and the 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 Michelle Bertolino, Electric Utility Director, at the above address and telephone number. A copy of the most recent comprehensive annual financial report of the City of Roseville (the "Annual Report") is available on Roseville's website at *http://www.roseville.ca.us/gov/finance/general_accounting/financial_statements.asp*. 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 Remarketing Memorandum and is not incorporated by reference herein.

Employees

General. As of June 30, 2014, 140 City of Roseville employees were assigned specifically to the Electric System. Certain functions supporting the Electric System operations, including meter reading, customer billing, collections and accounting, are performed by the Finance Department of the City.

The bulk 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 has a term through December 31, 2015. There have been no strikes or other work stoppages at Roseville, including at the Electric System.

Retirement Benefits. Substantially all permanent City employees, including those employees of 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 which acts as a common investment and administrative agent for its participating member employers. 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 entities within the State. CalPERS is a contributory plan deriving funds from employee contributions as well as from employer contributions and earning from investments. CalPERS issues a separate comprehensive annual financial report. Copies of the CalPERS annual financial report may be obtained from the CalPERS Executive Office, 400 Q Street, Sacramento, California 95814.

The contribution requirement of plan members and the City are established and may be amended by CalPERS. CalPERS determines contribution requirements using a modification of the Entry Age Normal Method, which is a projected benefit cost method. This method takes into account the benefits that are expected to be earned in the future as well as those already accrued. Accordingly, the normal cost for an employee is the level amount that would fund the projected benefit if it were paid annually from the date of employment until retirement. CalPERS uses a modification of the Entry Age Normal Method in which the employer's total normal cost is expressed as a level percentage of payroll in order to amortize any unfunded actuarial liabilities. The actuarial assumptions used to compute contribution requirements are also used to compute the actuarially accrued liability.

Employees of the Electric System participate in the CalPERS Miscellaneous Plan, and the Electric System pays a percentage of the City's Miscellaneous Plan expenses based on the number of employees. Active Miscellaneous Plan members are required to contribute 8.0% (6.25% for employees hired after January 1, 2013) of their annual covered salary. The City is required to contribute to at an actuarially determined rate. The rate for the year ended June 30, 2013 was 20.23% of annual covered payroll for Miscellaneous Plan employees. The City's annual pension costs (and total contribution amount) for the Miscellaneous Plan in which the employees of the Electric System participate for the Fiscal Years 2012-13, 2011-12 and 2010-11 amounted to $18,063,140 (of which $2,497,105 was contributed by the Electric System), $18,065,353 (of which $2,602,215 was contributed by the Electric Department) and $14,791,010 (of which $2,746,450 was contributed by the Electric System), respectively. The City paid 100% of the contributions required by CalPERS for each of such Fiscal Years. The budgeted contribution for Fiscal Year 2013-14 is $3,207,437.

As of June 30, 2012 (the most recent actuarial information available), the Entry Age Actuarial Accrued Liability for the Miscellaneous Plan, in which City employees assigned to the Electric System participate, was $429,218,174 and the Actuarial Value of Assets (which varies from market value) was $302,337,115, with an Unfunded Actuarial Accrued Liability of $126,881,059, resulting in a funded ratio of 70.4%. The portion of the plan allocable to Roseville Electric System employees is not separately calculated.

CalPERS uses a market-related value method of valuing the CalPERS plan's assets, which smooths the effect of short-term volatility in the market value of investments over a three-year period. The actuarial valuation assumptions used prior to 2012 include (a) a 7.75% investment rate of return (net of administrative expenses); (b) projected salary increases that range from 3.55% to 14.45% for Miscellaneous Plan members; (c) an inflation component of 3%; and (d) a 2-3% per year cost-of-living adjustment for retirees. Changes in liability due to plan amendments, changes in actuarial assumptions, or changes in actuarial methods are amortized as a level percentage of payroll on a closed basis over 20 years. Investment gains and losses are accumulated as they are realized and 10% of the net balance is amortized annually. On March 14, 2012, the CalPERS Board voted to reduce the discount rate, which is attributable to its expected price inflation and rate of return and investment rate of return (net of administrative expenses), from 7.75% to 7.5%. As a result, the amounts of CalPERS member public agency contributions will increase by 1% to 2% for Miscellaneous Plans.

On February 20, 2014, the CalPERS Board of Administration adopted new mortality and retirement assumptions as part of a regular review of demographic experience. Key assumption changes included longer post-retirement life expectancy and earlier retirement ages. The impact of the assumption changes will be phased in over five years, with a twenty-year amortization, beginning in the 2016-17 Fiscal Year. CalPERS has estimated that the adoption of the new assumptions will increase employer contribution rates (as a % of payroll) for most Miscellaneous Plans in the range of by 0.4% to 1.9% in the 2016-17 Fiscal Year and in the range of by 1.0% to 6.7% by 2020-21, depending on the benefit formula applicable to active members.

On September 12, 2012, the State of California passed Assembly Bill 340, the Public Employees' Pension Reform Act ("PEPRA"). PEPRA implemented new benefit formulas and final compensation period, as well as new contribution requirements for new employees hired on or after January 1, 2013 who meet the definition of new member under PEPRA. The provisions of AB 340 went into effect on January 1, 2013 with respect to State employees hired on that date and after; local government employee associations, including employee associations of the City, have a five-year window to negotiate compliance with AB 340 through collective bargaining. The City is currently in compliance with the provisions of AB 340.

CalPERS predicts that the impact of AB 340 on employers, including the City, and employees will vary, based on each employer's current level of benefits. To the extent that the new formulas lower retirement benefits, employer contribution rates could decrease over time as current employees retire and employees subject to the new formulas make up a larger percentage of the workforce. This change would, in some circumstances, result in a lower retirement benefit for employees than they currently earn. Additionally, CalPERS notes that changes arising from AB 340 could ultimately have an adverse impact on public sector recruitment in areas that have historically experienced recruitment challenges due to higher pay for similar jobs in the private sector.

The City is unable to predict what the amount ofCalPERS liabilities will be in the future or the amount of the CalPERS contributions which the City may be required to make, all as a result of the implementation of AB 340, and as a result of negotiations with its employee associations.

Other Post-Employment Benefits. The City also provides post-employment medical benefits ("OPEB benefits") to substantially all retirees, including those assigned to the Electric System, under the City of Roseville Other Post Employment Benefit Plan, a sole employer defined benefit healthcare plan. The City is responsible for establishing and amending the funding policy of the plan. The City 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, Public Financial Management, Inc. As of June 30, 2013, there were 525 participants receiving OPEB benefits under the plan.

The plan's annual required contribution ("ARC") is an amount determined in accordance with the parameters of GASB Statement 45. Plan members do not make contributions to the plan; the plan is funded entirely by the employer contributions. The ARC represents a level of funding that, if paid on an ongoing basis, is projected to cover the normal costs each year and amortize any unfunded actuarial liabilities (or funding excess) over a period not to exceed 30 years.

For the Fiscal Years 2012-13, 2011-12 and 2010-11, the City contributed 50% ($7,612,084), 33% ($4,972,333), and 415% ($38,457,645), and respectively, of the Annual OPEB Cost based on an actuarially determined Annual OPEB Cost of $15,317,140, $15,104,848, and $9,273,292, respectively. The City's Fiscal Year 2012-13 contribution included $5,131,475 for pay-as-you-go premiums and a $2,480,609 contribution to the OPEB Trust, to set aside monies for the long-term liability for OPEB Benefits. The City presently anticipates that its pay-as-you-go OPEB Pan benefit expense will be approximately $5,207,001 for Fiscal Year 2013-14, and that it will also contribute $2,100,000 to the OPEB Trust for such Fiscal Year. Of these contributions, the Electric System paid and contributed $612,827 for pay-as-you-go OPEB Plan benefit expenses and $524,146 (4.5% of payroll) to the OPEB Trust in Fiscal Year 2012-13. The Electric System presently anticipates that it will fund 100% of its ARC for Fiscal Years 2013-14 and 2014-15, including all pay-as-you-go OPEB Plan benefits and contributions to the OPEB Trust equal to 4.5% of payroll in each such Fiscal Year.

As of June 30, 2011 (the most recent actuarial information available), the Entry Age Actuarial Accrued Liability for the OPEB plan was $176,733,000 and the Actuarial Value of Assets was $34,626,000, with an Unfunded Actuarial Accrued Liability of $142,107,000, resulting in a funded ratio of 19.59%. The Electric System makes annual contributions for the OPEB Plan expense. The Actuarial Accrued Liability for the Electric System's OPEB obligation as of June 30, 2011 was $18,915,000, the Present Value of Benefits was $25,058,000 and the Actuarial Value of Assets was $3,706,000. In the June 30, 2011 actuarial valuation, the Entry Age Normal Actuarial Cost Method was used with a 30-year closed amortization period and level percentage of pay. The actuarial valuation assumptions used include (a) a 6.50% investment rate of return (net of administrative expense); (b) projected salary increases of 3.25% annually; (c) an inflation component of 3% per year; and (d) a healthcare trend of declining annual increases in costs of HMO and PPO plans, ranging from 9.00% to 9.40% in 2013 to 5.00% for years starting in 2021.

Additional information regarding the City of Roseville's retirement plans and other post-employment benefits can be found in the City's comprehensive annual financial reports, which may be obtained at *www.roseville.ca.us*.

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, 2014, the Electric System served an estimated 55,600 customers.

Customer Base. In Fiscal Years 2010-11, 2011-12 and 2013-14, the Electric System's customer base increased by almost 1.2% per year, and the customer base increased by more than 1.5% in Fiscal Year 2012-13. Population increased by an average of 1,657 for years 2011 and 2012, and increased by an average of 2,427 for years 2013 and 2014. Anticipated residential growth includes over 19,000 new residences associated with approved projects expected to be constructed upon build-out of current and developing specific plans. Roseville is currently planning the development of the Placer Ranch Specific Plan, which currently expects to add 5,000 new residential units. Recent commercial growth includes the South Placer Justice Center, a shared services center for Sutter Medical, a hardware support and services facility for Cokeva, and a data center for Quest.

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; 2011-2014 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	23,668,562
1990	45,189	175,290	29,760,021
2000	79,921	248,399	33,873,086
2010	118,788	348,432	37,253,956
2011	120,307	351,463	37,427,946
2012	122,102	355,450	37,668,804
2013	124,673	360,802	37,984,138
2014	126,956	366,115	38,340,074

Source: U.S. Bureau of Census and California State Department of Finance.

The largest employers in Roseville as of June 30, 2013 are set forth in the table on the following page:

CITY OF ROSEVILLE
LARGEST EMPLOYERS
(As of June 30, 2013)

Employer	Business	Number of Employees
Kaiser Permanente	Health Care	3,724
Hewlett-Packard	Technology	3,200
Sutter Roseville Medical Center	Health Care	1,654
Roseville Joint Union High School District	Education	1,299
City of Roseville	Government	1,254
Union Pacific Railroad	Railroad	1,168
PRIDE Industries	Employment Service	1,021
Roseville Elementary School District	Education	929
Wal-Mart (2 stores)	Retail	790
Telefunken (formerly NEC)	Technology	600

Source: City of Roseville.

The five-year history of new construction permits in Roseville is as follows:

CITY OF ROSEVILLE
BUILDING PERMITS
For Calendar Years 2009-2013

	2009	2010	2011	2012	2013
Residential Valuation (in thousands)					
Single Family	$125,257	$133,206	$91,310	$249,559	$118,548
Multifamily	3,747	0	0	0	6,632
Res. Alterations/Additions	1,621	2,808	7,329	3,082	3,395
TOTAL	$130,625	$136,014	$98,639	$252,641	$128,575
New Commercial	1,439	1,626	708	3,798	14,622
New Industrial	0	0	0	0	0
New Other	6,436	5,027	0	6,241	14,065
Com. Alterations/Additions	49,481	46,534	67,245	31,869	45,489
TOTAL	$57,356	$53,187	$67,953	$48,148	$74,176
New Dwelling Units					
Single Family	602	635	411	663	528
Multiple Family	49	0	0	0	224
TOTAL	651	635	411	663	752

Source: Construction Industry Research Board, Building Permit Summary.

The five-year history of assessed valuations of taxable property in Roseville is as follows:

CITY OF ROSEVILLE
TOTAL ASSESSED VALUATIONS
(Fiscal Year)
(Dollar Amounts in Thousands)

2009-10	2010-11	2011-12	2012-13	2013-14
$16,691,780	$15,508,581	$14,773,035	$14,745,890	$15,910,815

Source: City of Roseville and Placer County Assessor.

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]

	Fiscal Year Ended June 30,				
	2010	2011	2012	2013	2014[2]
Number of Customers:[3]					
Residential	46,400	47,021	47,611	48,387	49,000
Commercial	6,411	6,436	6,505	6,561	6,600
Total	52,811	53,457	54,115	54,948	55,600
MWh Deliveries Average:					
Residential	433,494	422,949	440,311	443,489	434,800
Commercial	774,619	742,613	752,001	750,694	748,300
Total MWh sales	1,208,112	1,165,562	1,192,312	1,194,183	1,183,100
Revenues ($ in 000s):					
Residential	$ 56,115	$ 60,941	$ 65,760	$ 66,206	$66,400
Commercial	80,097	85,570	88,610	89,228	92,600
Total Revenues from Sale of Energy	$136,212	$146,511	$154,369	$155,434	$159,000
Peak Demand (MW)	323.7	331.4	312	330	340.0

(1) Revenues listed are as billed. For realized revenues, see the table under "Historical Revenues, Expenses and Debt Service Coverage" below.
(2) Estimated.
(3) 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, 2014, the ten largest customers of Roseville's Electric System by usage accounted for an estimated 23.50% of total kWh sales and 18.50% of total Electric System revenues. The largest customer accounted for an estimated 8.60% of total kWh sales and 6.37% of total Electric System revenues. The smallest of the ten largest customers accounted for an estimated 0.81% of total kWh sales and 0.67% of total Electric System revenues.

Sources of Power Supply

General

Roseville has a diverse portfolio of resources that includes large hydro, geothermal, natural gas fired thermal, system power contracts, and additional contracts for renewable supply. 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 No. 1 (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 Central Valley Project net generation and entitlements to the output of several NCPA projects.

The table on the following page provides an estimated summary of the City's sources of power supply for Fiscal Year 2013-14.

CITY OF ROSEVILLE
ELECTRIC SYSTEM
SOURCES OF POWER SUPPLY
Fiscal Year 2013-14 (Estimated)

Source	Type	Area	Capacity Available (MW)[1]	Actual Power Energy (GWh)[2]	% of Total
Generation:					
Roseville Energy Park[3]	Natural Gas	Local	155	629	52%
Roseville Power Plant 2	Natural Gas	Local	48	1	0
Purchased Power:					
Western[4]	Hydro	Western	62	107	9
NCPA					
Geothermal Project	Geothermal	CAISO	8	65	5
Hydroelectric Project	Hydro	CAISO	29	23	2
Capital Facilities Project,Unit One	Natural Gas	CAISO	20	6	1
Open Market Purchases:					
Renewable Purchases	Geo/Small Hydro		8	148	12
Other Purchases					
Long-term hedged[5]	Various		50	162	14
Short-term un-hedged	Various		0	78	6
TOTAL*			380*	1,220*	100%*
Peak Demand (MW)			340		
Capacity Reserve Percent			12%		

(1) Capacity in MW and available for system peak.
(2) One gigawatt hour (GWh) equals 1 million kilowatt hours (kWh).
(3) Includes slight de-rating for summer (ambient temperatures).
(4) Includes reserve capacity.
(5) Capacity includes long-term and seasonable purchases.
* Numbers may not total due to rounding.
Source: City of Roseville.

Roseville Energy Park

Roseville Energy Park, is a 120 MW base load and 160 MW duct fired combined cycle, natural gas fueled power plant. The Roseville Energy Park power island is comprised of two Siemens SGT 800 combustion turbine units and a Siemens STG 900 steam turbine. The Roseville Energy Park utilizes duct firing within the Heat Recovery Steam Generator ("HRSG") and a Liquid Management System ("LMS"). The plant has been in commercial operation since October of 2007 and serves as an intermediate load resource for Roseville's electric power needs. Roseville Energy Park is owned and operated by the City.

The Roseville Energy Park is directly connected to Roseville's distribution system and thus avoids transmission costs and losses. Roseville schedules and dispatches the plant against the avoided cost of electric market purchases to meet its load requirements, primarily from the California Independent System Operator ("CAISO"), and taking into account all known costs and constraints. Roseville Energy Park is also used to provide load following reserves to the extent they are not available from the electric markets. The City operates the Roseville Energy Park during periods where the alternative cost of supplying customer loads is higher, and idles the plant when alternative electric purchases are less expensive than Roseville Energy Park operations. The estimated system base capacity factor for Roseville Energy Park for Fiscal Year 2013-14 was approximately 46%. Having the Roseville Energy Park in place allows the City to take advantage of attractive market prices and provides economic flexibility to the plant and overall portfolio.

Roseville Power Plant 2

The Roseville Power Plant 2 consists of two 24 MW simple cycle combustion turbines for a total of 48 MW of capacity. These units were previously part of the NCPA Combustion Turbine Project No. 1 of which Roseville was a participant. On September 1, 2010 Roseville took ownership of the two units connected to the Roseville electric distribution system and ceased participation in the NCPA project. The units provide capacity and reserves for Roseville and are used for peaking energy and limited high value economic dispatch.

Western Area Power Administration

Roseville has long-term contracts with Western that provide a 4.5817% share of the net output of the Central Valley Project ("CVP"), provide for interconnection and interconnected operations with Western's transmission system, and provide for transmission services. On January 1, 2015, Roseville's share of the net output of the CVP will increase to 4.85333%. The power supply contract provides varying amounts of capacity and energy depending upon hydrological and storage conditions of the CVP. The output is reduced by Western's project use, first preference customer allocations and control area obligations. Roseville is directly connected to Western's transmission system and acquires reserves under contract that include regulation and frequency response service, and spinning and non-spinning reserves. The term of the power supply contract extends through December 31, 2024.

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 purchased from NCPA a 12.00% entitlement share in the Hydroelectric Project. Roseville has purchased from NCPA a 36.50% entitlement share in the NCPA Capital Facilities Project, Unit One. Roseville has purchased from NCPA a 7.88% entitlement share in the Geothermal Project. For a description of such resources, see "THE PROJECT" and "OTHER NCPA PROJECTS" in the front part of this Remarketing Memorandum. For each of these NCPA generation projects in which Roseville participates, Roseville is obligated to pay, on an unconditional take-or-pay basis, 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 Remarketing Memorandum.

Long Term Purchases

Roseville has historically entered into long term purchases to hedge electricity costs. With the passage of Senate Bill X1 2, the California Renewable Energy Resources Act, Roseville has additional incentive to enter into long term contracts. Certain contracts over ten years have the ability to have renewable energy "banked" to be used to meet future compliance periods. One requirement for "banking" is a renewable contract must have a term of ten years or greater. The current portfolio has a transaction with the City of Santa Clara ("Santa Clara") for renewable energy that started in 2012 and extends through 2022. The contract delivered 185,000 MWh in 2013 and is expected to deliver between 50,000 and 60,000 MWh per year through 2022. Roseville has also entered into a ten year solar energy purchase with First Solar which contract is expected to deliver over 250,000 MWh over ten years beginning in 2015. See also "DEVELOPMENTS IN THE CALIFORNIA ENERGY MARKETS–State Legislation–*Renewable Portfolio Standards*" in the front part of this Remarketing Memorandum for more information on SB X1 2.

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.

Electricity is generally sold or acquired in 25 MW increments on a seasonal or annual basis. Roseville also typically enters into seasonal and short-term purchases for varying terms from a number of power suppliers. Typical short-term purchase terms range from 1 to 3 months, though these contracts can occasionally be as long as 12 months.

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 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 "DEVELOPMENTS IN THE CALIFORNIA ENERGY MARKETS—State Legislation" in the front part of this Remarketing Memorandum.

Power Supply Risk Management

The Electric System has a rigorous risk management program to ensure that customers will, to the best extent possible, be insulated from the volatility of supply prices. Roseville established a Risk Oversight Committee ("ROC"), as well as extensive risk management policies and procedures. The ROC includes two members of the City Council, two members of the Roseville Public Utilities Commission, the City Manager, the Assistant City Manager, the City Treasurer/Financial Executive, the City Attorney, and the Electric Utility Director. The ROC meets quarterly to review energy trading activities and to ensure their adherence to the risk management policies.

All energy purchases are made to supplement existing resources to meet forecasted load requirements. Generally, Roseville purchases or sells energy that is deficit or surplus to its retail customer needs independently within a 3-year horizon and by using the scheduling and load following services of ACES Power Marketing ("ACES") within a 30-day horizon. Roseville's risk management policies include short-term and long-term measures.

In general, short-term measures limit exposure due to market prices, hydro conditions, and unit outages for the coming 12 months to 7.5% or less of Roseville's expected purchased power cost and limit portfolio open volume to no more than +/- 10% of forecast load.

Roseville's long-term risk management strategy encourages a balanced "layered" energy portfolio. The Energy Hedge Policy provides a ceiling and floor for the required hedged energy (electricity and natural gas) to meet expected loads as follows:

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. Allowed instruments in the hedging program include:

- Electric forward sales or purchases with authorized counterparties
- Electric tolling arrangements with qualified counterparties
- Bilateral Gas contracts with qualified counterparties
- Gas futures, Floors and Caps through the NYMEX or other approved market

Roseville's natural gas procurement strategy primarily involves purchasing natural gas for REP's operation at a daily index price. Roseville hedges its daily index purchases with monthly financial fixed for floating swap contracts or physical forward purchases in accordance with its Energy Hedge Policy described above. For the period January 1, 2014 through December 31, 2016, Roseville has fixed the price of approximately 12 million

MMBtu of natural gas in this manner. These financial contracts are divided between BP Energy, J Aron and Company, JP Morgan Energy Ventures, Macquarie Energy, and Shell Energy.

Natural Gas Prepayment

The Roseville Natural Gas Financing Authority entered into a 20-year pre-paid natural gas supply contract in January 2007 with Merrill Lynch Commodities Inc. ("MLCI"). The natural gas the City is obligated to purchase under the pre-paid gas supply agreement provides approximately 40% of Roseville's expected 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.

Regional Transmission Facilities

Western Area Power Administration Network Integrated Transmission Service Agreement ("NITS"). Roseville's electrical system interconnects with the transmission system of Western. The Western transmission system is part of the 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 Combustion Turbine Project Number One over the Western transmission system. Roseville contracts for transmission service to meet its load under a NITS contract that expires on December 31, 2014. This contract provides for imports of electricity from various delivery points into Roseville's Electric System. Roseville pays a proportionate share of Western's cost for operating and maintaining the system, which is currently $2.6 million per year.

Balancing Authority of Northern California. The Balancing Authority of Northern California ("BANC") is a joint powers authority consisting of the Sacramento Municipal Utility District ("SMUD"), the Modesto Irrigation District ("MID"), Roseville, the City of Redding and the Trinity Public Utility District. With a peak electricity demand of around 5,000 MW, BANC is the third largest balancing authority in California, serving 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.

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. Roseville estimates that approximately half of its incremental short-term energy needs are acquired from the CAISO Controlled Grid.

TANC California-Oregon Transmission Project. Roseville is a member of the Transmission Agency of Northern California ("TANC") and has executed 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 2024 and is approximately $700,000 per year. See also "CITY OF ALAMEDA—Joint Powers Agency 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 this Tesla-Midway Transmission Service is 5 MW. Roseville utilizes its allocation of Tesla-Midway Transmission Service for firm and non-firm power transactions when available and economic to do so. See also "CITY OF ALAMEDA—Joint Powers Agency—*TANC Tesla-Midway Transmission Service*" herein for additional information regarding the TANC Tesla-Midway Transmission Service.

Roseville Layoff of COTP and Tesla-Midway Service. In 2009, with the assistance of TANC, Roseville reached an agreement with SMUD, Turlock Irrigation District ("TID") and MID to lay off its COTP and Tesla-Midway Transmission Service rights to TANC, and subsequently for TANC to layoff these rights to SMUD, TID and MID. During the 15-year initial term of the agreement (and a subsequent five-year extension if so elected by the parties), SMUD, TID and Modesto were assigned responsibility for all rights and obligations associated with this entitlement and with the TANC Agreement as specified in the layoff agreement. For the same period, SMUD and TID assumed all rights and obligations and costs associated with Roseville's Tesla-Midway Service rights.

Early Termination of COTP Layoff. In March 2014, Roseville executed an amendment to the long-term layoff agreement for its COTP interest, effectively returning to Roseville all of its rights and obligations to the COTP project under the TANC Agreement effective July 1, 2014.

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 703 miles of underground lines and 17 substations. Roseville performs continued maintenance on its distribution system to sustain service reliability.

Dispatch and Scheduling

Roseville contracts with 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 2012-13).

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 (as recently amended from every three 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 is participating in the State effort, and the Roseville City Council approved the new ten-year energy efficiency goals in March 2013.

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 recent California legislation relating to the electric energy market, see "DEVELOPMENTS IN THE CALIFORNIA ENERGY MARKETS—State Legislation" in the front part of this Remarketing Memorandum.

Insurance

The City is a member of the California Joint Powers Risk Management Authority ("CJPRMA"), which covers general liability claims, property, and boiler and machinery losses. Once the City'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. For the City's projected Fiscal Year 2013-14, the City's premium was $429,658 with an additional $1,625 charge to reflect the fees to access certain online risk management systems. Total premium cost to the City was $429,658. CJPRMA has purchased commercial insurance against property damage and boiler and machinery claims. Property damage is covered up to $300,000,000 with a self-insured retention of $25,000. For the City's projected Fiscal Year 2013-14, the City's premium was $249,319. Boiler and Machinery damage is covered up to $21,250,000 with a self-insured retention of $5,000. For the City's projected Fiscal Year 2013-14, the annual premium paid was $31,170.

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 31, 2013 through October 31, 2014, the City's premium was $419,784. The City has also purchased fiduciary insurance specifically to cover the OPEB Trust; see "Employees–*Other Post-Employment Health Benefits*" above. The self-insured retention was $15,000 per claim up to a $3,000,000 limit. For the policy term of January 15, 2014 through January 15, 2015, the City's premium was $33,024.

The City 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. The City has a self-insured retention of up to $350,000 per claim. During Fiscal Year 2013-14, the City projects that it contributed $552,561 for current year coverage.

Projected Capital Improvement Plan

Roseville's currently anticipated capital improvement plan 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 Plan Summary below, Roseville has planned Electric System capital spending of approximately $72 million over the five Fiscal Years 2014-15 through 2018-19, of which $19 million is included in the Fiscal Year 2014-15 budget. Funds for the additional $53 million will be requested when necessary.

CITY OF ROSEVILLE
ELECTRIC SYSTEM
CAPITAL IMPROVEMENT PLAN SUMMARY

Fiscal Year Ending June 30	Planned Capital Improvement Projects
2014-15	$ 18,533,000
2015-16	16,637,000
2016-17	14,001,000
2017-18	12,703,000
2018-19	9,876,000
Total:	$71,750,000

Source: City of Roseville.

Roseville currently expects to fund the capital expenditures with revenues collected from rates and development fees.

Electric Rates

Rate Setting Procedure. Under the City Charter and State law, the City 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 California Public Utilities Commission 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 are payable the costs and expenses of the Electric System.

Service Charges and Demand Charge as of July 1, 2014. Roseville's monthly residential electric rates currently include a $18.00 basic service charge, the Renewable Energy Surcharge of $0.0067 per kWh, the Greenhouse Gas Surcharge of $0.0002 per kWh, plus $0.1024 per kWh consumed up to 500 kWh, $0.1476 per kWh consumed from 501-1000 kWh, and $0.1672 per kWh for consumption in excess of 1000 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 $28.00 to $76.00, the Renewable Energy Surcharge of $0.0067 per kWh, the Greenhouse Gas Surcharge of $0.0002 per kWh, plus $0.1044 to $0.1267 per kWh consumed. Medium business customers are also subject to a demand charge of $4.62 per kW per month.

For large business customers, the monthly basic service charge is $567.00, the Renewable Energy Surcharge of $0.0067 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 $0.0698 to $0.1443 per kWh. Large business customers are also subject to a seasonal demand charge of $3.38 per kW per month in winter and $11.66 per kW per month in summer.

For very large business customers, the monthly basic service charge is $684.00, the Renewable Energy Surcharge of $0.0067 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 $0.0689 to $0.1428 per kWh. Very large business customers are also subject to a seasonal demand charge of $3.28 per kW per month in winter and $11.29 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 low precipitation levels from July 2012 through June 2013, there was a $0.0013 per kWh surcharge for all customers in effect from July 2013 through June 2014. With low precipitation levels continuing from July 2013 through April 2014, the surcharge recently increased to $0.00348 per kWh surcharge in effect from July 2014 through June 2015.

Recent History of Electric Rate Adjustments. From Fiscal Year 2008-09 through 2014-15, Roseville's retail electric rates have increased an average of approximately 4.8% annually. The following table sets forth Roseville's recent rate change history.

CITY OF ROSEVILLE
ELECTRIC RATE CHANGES
Fiscal Years 2008-09 through 2014-15

Date	Percent Change (Average)
July 1, 2014	2.00%
July 1, 2013	2.00
January 1, 2011	6.20
July 1, 2010	6.20
January 1, 2010	6.20
February 1, 2009	6.00

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 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% 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. The Rate Stabilization Fund has a projected, unaudited balance of $47 million as of June 30, 2014. The City 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

Electric System Revenue Certificates and Bonds. As of June 30, 2014, Roseville had outstanding approximately $234.5 million 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 remaining 2004 bonds were refunded in July 2014.

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. Certain of 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 June 30, 2014)

	Outstanding Debt[(2)]	Roseville Participation[(3)]	Roseville Share of Outstanding Debt[(2)]
NCPA			
Geothermal Project	$ 41.3	7.88%	$ 3.3
Hydroelectric Project	401.2	12.00[(4)]	40.1[(4)]
Capital Facilities Project	48.1	36.50	17.6
TANC			
Bonds	314.0	2.30[(5)]	7.3[(5)]
TOTAL*	$804.9		$68.3

(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.
(5) Beginning in 2009, Roseville laid off its COTP obligations to other TANC Members for an initial fifteen-year term. Roseville recently negotiated an early termination of the COTP layoff and effective July 1, 2014, Roseville will re-assume responsibility for payment of its participation obligation. See "Regional Transmission Facilities—*TANC California-Oregon Transmission Project*" above. Roseville's actual payment 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.
Note: Numbers may not total due to rounding.
Source: City of Roseville.

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. In connection with certain of such joint powers agency obligations, the respective joint powers agency has entered into interest rate swap agreements relating thereto for the purposes of substantially fixing the interest cost with respect thereto. There is no guarantee that the floating rate payable to the respective joint powers agency pursuant to each of the interest rate swap agreements relating thereto 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).

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 Financial Report for Fiscal Year 2012-13 was audited by Maze & Associates, Walnut Creek, 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 may not be fully described below. Such notes constitute an integral part of the audited financial statements. Copies of these reports are available on the City'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 the City's Electric Fund for Fiscal Years 2009-10 through 2012-13 on a historical basis and for Fiscal Year 2013-14 on a projected, unaudited basis. 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 the City'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 are accounted for in the City's audited financial statements (for Fiscal Years 2009-10 through 2012-13) but the presentation in the audited financial statements may not necessarily correlate to the line item designations in the table. The figures shown for fiscal year 2013-14 are on a projected, unaudited basis.

CITY OF ROSEVILLE
ELECTRIC FUND
STATEMENT OF REVENUES AND EXPENSES
Fiscal Years 2009-10 through 2013-14
(Dollars in Thousands)

	2009-10	2010-11	2011-12	2012-13	2013-14[1]
Revenues					
Charges for Services	$137,660	$146,734	$153,913	$156,986	$159,000
Sale of Wholesale Power [2]	22,798	11,436	0	0	0
Other [3]	2,857	5,065	6,228	2,016	2,099
Total Revenues	$163,315	$163,235	$160,141	$159,002	$161,099
Operating Expenses					
Power Supply	$124,842	$103,999	$ 95,969	$ 96,314	$ 93,561
Non-Power Costs [4]	16,164	14,184	18,511	18,744	19,981
Indirect Costs and Transfers [5]	8,960	9,074	8,835	8,402	9,123
Total Operating Expenses	$149,966	$127,257	$123,315	$123,460	$122,666
Net Revenue	$ 13,349	$ 35,978	$ 36,826	$ 35,542	$ 38,433
Debt Service	$ 14,608	$ 16,310	$ 17,136	$ 16,942	$ 16,884
Adjusted Net Revenue					
Net Revenue	$ 13,349	35,978	36,826	$ 35,542	$ 38,433
Operating Transfers and Other Expense (net) [6]	(3,983)	(4,134)	(982)	9	0
Transfers from Rate Stabilization Fund [7]	17,595	0	0	0	0
Interest Revenue (excluding unrealized gain/loss)	996	306	536	381	313
Adjusted Net Revenue	$ 27,957	$ 32,150	$ 36,380	$ 35,932	$ 38,747
Debt Service Coverage Ratio	1.91	1.97	2.12	2.12	2.29
Rate Stabilization Fund Balance [8]	$24,215	$30,918	$37,785	$41,386	$46,994
Transfers (to) Rate Stabilization Fund	0	(6,288)	(6,419)	(3,305)	(5,387)
Debt Service Coverage ratio including Rate Stabilization Fund [9]	3.57	3.48	3.95	4.37	4.76

Source: City of Roseville.

(1) Fiscal Year 2013-14 projected, unaudited.
(2) Represents multi-year forward energy sale, which ceased after Fiscal Year 2010-11.
(3) Remediation Revenue stopped being reported in Other Revenue in Fiscal Year 2012-13, and is now reflected as a net in the Power Supply Operating Expenses item.
(4) Includes distribution operations and administration expenses, including the Electric System's share of CalPERS costs.
(5) Represents operating payments to the City as reimbursement for the Electric System's share of certain overhead expenses such as information technology, meter reading, traffic signal transfer, enterprise asset management contribution, facility lease payments, utility exploration center operations, retired employees' health costs, the Electric System's share of GIS system costs, payroll, human resources, OPEB costs, etc.
(6) Represents inter-fund transfers to fund non-capital rehabilitation projects and includes subventions/grants transfers in.
(7) Represents transfers from Rate Stabilization Fund to offset increasing energy costs and mitigate rate impacts.
(8) Represents available resources as of June 30, which includes cash as well as moneys due the fund from internal borrowing.
(9) Funds on deposit in the Rate Stabilization Fund may be included in Adjusted Annual Revenues for purposes of determining compliance with Roseville's rate covenant.

CITY OF SANTA CLARA

Introduction

The City of Santa Clara ("Santa Clara") is a charter city located in the State of California. 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 members of Santa Clara City Council are elected city-wide for staggered four year terms. The Santa Clara electric utility department is under the direction of the Director of Electric Utility who, together with certain other senior managers of the electric utility department, is appointed by and reports to the Santa Clara City Manager.

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, 2014, Santa Clara had an estimated population of 121,229. For the fiscal year ended June 30, 2014, Santa Clara served an average of 53,139 customers per month, had total sales of 2,998 GWh and a peak demand of 478.9 MW. In fiscal year 2013-14, approximately 91% of Santa Clara's energy sales were made to commercial and industrial customers.

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.

Only the 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) 261-5292. A copy of the most recent annual report of the Santa Clara electric utility fund (the "Annual Report") may be obtained from John C. Roukema, Director of Electric Utility, at the above address and telephone number, and is also available on Santa Clara's website at *www.siliconvalleypower.com*. 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 Remarketing Memorandum, is not incorporated by reference herein.

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, 2014.

CITY OF SANTA CLARA
ELECTRIC UTILITY DEPARTMENT
POWER SUPPLY RESOURCES*
(For the Fiscal Year Ended June 30, 2014)

Source	Capacity Available (MW)	Recorded Energy (GWh)	Percent of Total Energy
City-Owned Generating Facilities[1]			
Cogeneration	7.0	50.9	1.6%
Stony Creek Hydro System	11.6	10.5	0.3
Gianera Generating Station	49.5	0.0	0.0
Grizzly Project	17.7	16.4	0.5
Don Von Raesfeld Power Plant	147.8	902.9	28.7
Purchased Power:[2]			
Western[3]	136.0	208.3	6.6
Altamont Wind	17.1	21.3	0.7
Manzana Wind	50.0	143.9	4.6
G2 (Landfill)	2.6	11.9	0.4
Ameresco (Landfill)	0.8	2.6	0.1
Ameresco FWD (Landfill)	4.6	4.8	0.2
Ameresco VASCO (Landfill)	4.6	12.7	0.4
TriDam-Beardsley	11.5	4.7	0.2
TriDam-Donnells	72.0	61.1	1.9
TriDam-Tulloch	26.0	51.6	1.6
Rosamond (Recurrent Solar)	20.0	31.8	1.0
Market Purchases	50.0	166.8	5.3
Joint Power Agencies:			
NCPA			
Geothermal Project	71.7	367.2	11.7
Combustion Turbine Project	30.9	0.6	0.0
Lodi Energy Center Project	72.0	321.8	10.2
Hydroelectric Project	93.7	66.6	2.1
M-S-R PPA			
San Juan	51.0	382.3[4]	12.2
Big Horn I Wind Energy	105.0	261.3	8.3
Big Horn II Wind Energy	17.5	43.3	1.4
Total	1,070.6	3,145.1	100.0%

* Columns may not add to totals due to rounding.
(1) Rated or name-plate capacities.
(2) Capacity Available from Purchased Power resources represents entitlements, firm allocations and contract amounts.
(3) Santa Clara purchased varying amounts of capacity from Western during the year.
(4) Figures represent energy delivered to Santa Clara net of sales to market.
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 in Santa Clara and delivers power to Santa Clara's electric distribution system. Santa Clara upgraded this plant to obtain a new name-plate rating of 7.4 MW, effective July 1995. Fuel for the cogeneration plant (natural gas) is generally acquired under term contracts at prices fixed for the contract term.

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.

Gianera Generating Station. Santa Clara owns and operates a nominal 49.9 MW dual fuel (natural gas and fuel-oil) combustion turbine generating plant consisting of two 25 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.

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. 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 57.3 GWh in an average water year and 26.1 GWh in dry years. For the fiscal year ended June 30, 2014, the Grizzly Project generated 16.4 GWh of energy.

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.

Don Von Raesfeld Power Plant. Santa Clara constructed and placed into commercial operation on March 22, 2005, a 122 MW nominal/147 MW peak, natural gas-fired, combined cycle power plant known as the "Don Von Raesfeld Power Plant" (initially designated by the Santa Clara City Council as the Pico Power Plant). The Don Von Raesfeld Power Plant is located in an industrial area of the City of Santa Clara, on the site of Santa Clara's Kifer Receiving Station. The Don 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 Don 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, 2014, the Don Von Raesfeld Power Plant generated 902.9 GWh of energy. Santa Clara has long-term agreements with Shell Energy North America and M-S-R Energy Authority (see "Joint Powers Agency Resources—*M-S-R Energy Authority—Gas Prepay*" below) 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. Fully baseloaded, the Don 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.

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. 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. Santa Clara is currently taking delivery of its share of the capacity and associated energy from the Geothermal Project. For the fiscal year ended June 30, 2014, Santa Clara received 367.2 GWh of electric energy from the Geothermal Project. Santa Clara's share of the current California Independent System Operator ("CAISO") maximum rated capacity of the project is 71.7 MW.

Santa Clara has a 55 MW share in NCPA's Geysers Transmission Project, which provides a link from the Geysers to PG&E's bulk transmission system. Through a long-term contract with the California Department of Water Resources ("CDWR"), sufficient additional transmission capability on the same line is available for the balance of Santa Clara's share of the capacity and energy produced by the NCPA Geothermal Project. Santa Clara obtains additional transmission services to Santa Clara for its share of the output of NCPA Geothermal Project from arrangements with PG&E and the CAISO.

NCPA Combustion Turbine Project No. 1. Santa Clara has purchased a 25% entitlement share in NCPA's Combustion Turbine Project No. 1 pursuant to a power sales contract with NCPA, which was amended in 2007 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, 2014, Santa Clara received 600 MWh of electric energy from the Combustion Turbine Project No. 1.

NCPA Hydroelectric Project. Pursuant to a power sales contract, 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). 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. Santa Clara is using this entitlement to serve peak load and to provide capacity to support non-firm purchases of energy at market prices. For the fiscal year ended June 30, 2014, Santa Clara received 66.6 GWh of electric energy from the NCPA Hydroelectric Project (reflecting the below-average water year). Santa Clara receives this entitlement to its system by using transmission service available under its Metered Subsystem Agreement ("MSS Agreement") with the CAISO.

NCPA Lodi Energy Center Project. Pursuant to a power sales agreement, Santa Clara has purchased from NCPA a 25.75% entitlement share in NCPA's Lodi Energy Center Project and is responsible for 46.16% of the debt service for the Lodi Energy Center Revenue Bonds, Issue One. Santa Clara's payment to NCPA under such power sales agreement, including debt service on NCPA's Lodi Energy Center Revenue Bonds, Issue One, constitute an operating expense of Santa Clara's electric system. Santa Clara is using this entitlement (approximately 72 MW) to provide base, peak load and ancillary services to meet electric demand and reliability requirements. The Lodi Energy Center Project was placed into commercial operation on November 27, 2012 and was in ramp-up mode for the first few months. For the fiscal year ended June 30, 2014, Santa Clara received 321.8 GWh of electric energy from the NCPA Lodi Energy Center Project. Santa Clara receives this entitlement to its system by using transmission service available under its Metered Subsystem Agreement ("MSS Agreement") with the CAISO.

For a description of such NCPA resources, see "THE HYDROELECTRIC PROJECT" and "OTHER NCPA PROJECTS" in the front part of this Remarketing Memorandum. See also "Indebtedness; Joint Powers Agency Obligations" below.

TANC California–Oregon Transmission Project. Santa Clara is a member of the Transmission Agency of Northern California ("TANC") and has executed the TANC Agreement for a participation percentage of TANC's entitlement of COTP transfer capability. Santa Clara 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 (approximately 121 MW) of the City of Vernon, California ("Vernon"), one of the original owners of the COTP.

TANC utilized a combination of cash and the issuance of commercial paper (which was subsequently refunded with 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 the TANC Agreement, Santa Clara has historically been obligated to pay 20.47% of TANC's COTP operating and maintenance expenses and 20.70% of TANC's COTP debt service and 22.16% of the Vernon acquisition debt. Santa Clara has been entitled to 20.4745% of TANC's share of COTP transfer capability (approximately 278 MW net of third party layoffs of TANC) on an unconditional take-or-pay basis. Beginning July 1, 2014 Santa Clara laid-off 147 MWs of this entitlement to other TANC members 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's portion of the operating and maintenance expenses will be 10.0040% and Santa Clara's share of the COTP debt service will be approximately 10.14%. Santa Clara will remain contractually obligated for its full participation share. See "CITY OF ALAMEDA—Joint Powers Agency Resources—*TANC California-Oregon Transmission Project*" for a further description of the COTP and the TANC Agreement.

Santa Clara's share of annual operating and maintenance expenses and debt service for the COTP through TANC has been over $12 million per year through the end of the current fiscal year. Beginning in fiscal year 2014-15, Santa Clara's share of annual operating and maintenance expenses and debt service for the COTP through TANC is expected to be approximately $6.4 million per year. The reduction in share is due to the layoff described in the paragraph above. Santa Clara's payment to TANC, including debt service on TANC's revenue bonds, constitute an operating expense of the electric system.

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 and Santa Clara's share of the SCL-NCPA Exchange Agreement (described below under "Purchased Power"). Santa Clara also participates with other TANC members in offering unused and unencumbered transfer capability for use by other entities in an open and efficient manner in accordance with TANC posted tariffs.

On April 30, 2014, TANC filed a formal complaint against PG&E with FERC alleging an anticipated violation by PG&E of its rate schedule providing for coordinated operation of its portion of the COTP. TANC alleges that PG&E is failing to adequately develop, maintain and support its portion of the COTP because PG&E has not put in place the necessary infrastructure or agreements to replace a contract it has with the California Department of Water Resources (the "Comprehensive Agreement") upon its scheduled expiration on December 31, 2014. The Comprehensive Agreement includes remedial action obligations on the part of DWR (the "Remedial Action Obligations") which support COTP operations and the loss of such capability, TANC alleges, could result in the degradation of the capability of the COTP. TANC has requested fast track processing of its complaint by FERC to obtain relief prior to December 31, 2014. Santa Clara is unable to predict the outcome or impact of these proceedings on Santa Clara's COTP interest.

TANC Tesla–Midway Transmission Service. TANC and certain TANC members have arranged for 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. See "CITY OF ALAMEDA—Joint Powers Agency Resources—*TANC Tesla-Midway Transmission Service*" for a further description of the Tesla-Midway Transmission Service.

Santa Clara's share of Tesla–Midway Transmission Service is 81 MW. Santa Clara had an agreement with SMUD to layoff 30 MW of its capacity of the Tesla-Midway Transmission Service, for the period January 1, 2009 through June 30, 2013. The layoff allowed Santa Clara to procure more Congestion Revenue Rights in the CAISO allocation process thus allowing Santa Clara to more effectively hedge congestion exposure under the CAISO Market Redesign and Technology Upgrade (MRTU). Santa Clara anticipates continuing to use its share of the

TANC Tesla–Midway Transmission Service to provide access to power supplies located in the southwest, including delivery of power and energy from the San Juan Unit No. 4. See "*—M-S-R PPA Purchased Power—San Juan*" below.

M-S-R PPA Purchased Power–San Juan. Santa Clara, along with the Modesto Irrigation District ("Modesto") 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"). M-S-R PPA owns a 28.8% (approximately 146 MW) interest in the San Juan Unit No. 4 (the "M-S-R PPA San Juan Unit No. 4 Interest"). The San Juan Unit No. 4 is a coal-fired steam electric generating unit with a net generating capability of 507 MW, located in San Juan County, New Mexico, which was constructed and is operated by Public Service Company of New Mexico ("PNM"). The San Juan Unit No. 4 is one of four generating units that together make up the San Juan Generating Station (the "SJGS"). M-S-R PPA financed the acquisition of the M-S-R PPA San Juan Unit No. 4 Interest through the issuance of revenue bonds. See "Indebtedness; Joint Powers Agency Obligations" below.

Santa Clara has purchased from M-S-R PPA a 35% entitlement share in the M-S-R PPA San Juan Unit No. 4 Interest pursuant to a power sales agreement (the "M-S-R PPA Agreement"), which includes approximately 51.1 MW of capacity and associated energy from the M-S-R PPA San Juan Unit No. 4 Interest. Pursuant to the M-S-R PPA Agreement, Santa Clara, in exchange for its above-mentioned percentage purchased, is unconditionally obligated to pay its share of all of M-S-R PPA's costs associated with M-S-R PPA San Juan Unit No. 4 Interest, including debt service on revenue bonds which were issued to finance the acquisition of the M-S-R PPA San Juan Unit No. 4 Interest, and subject to a "step up" obligation of up to 25% upon the unremedied default of another M-S-R PPA participant.

Santa Clara uses its M-S-R PPA San Juan Unit No. 4 Interest capacity and energy to serve in its own system or for short-term layoffs to others based upon monthly economic dispatch considerations. M-S-R PPA obtains firm transmission to transmit to the M-S-R PPA members the capacity and energy of the M-S-R PPA San Juan Unit No. 4 Interest through firm transmission service agreements executed with Los Angeles Department of Water and Power ("LADWP") and via the M-S-R PPA Southwest Transmission Project (described below). For the fiscal year ended June 30, 2014, Santa Clara received 382.3 GWh of energy from the M-S-R PPA San Juan Unit No. 4 Interest. Beginning in early 2014, Santa Clara ended its firm transmission service agreement with Southern California Edison Company, after an economic analysis found that Santa Clara could access the CAISO's new firm use transmission and arrange for delivery of the San Juan power more economically.

In connection with the cap-and-trade program adopted by the California Air Resources Board pursuant to Assembly Bill 32 ("AB 32") to reduce greenhouse gas emissions, M-S-R PPA members are required to account for carbon emissions of the M-S-R PPA San Juan Unit No. 4 Interest and provide off-setting allowances thereto for any electricity delivered to California. See "DEVELOPMENTS IN THE CALIFORNIA ENERGY MARKETS—State Legislation—*Greenhouse Gas Emissions*" in the front part of this Remarketing Memorandum.

On February 15, 2013, PNM, the New Mexico Environment Department and the United States Environmental Protection Agency (the "EPA") agreed to pursue a plan that could provide a Best Available Retrofit Technology ("BART") path to comply with federal visibility rules at the SJGS. The terms of the non-binding agreement results in the retirement of the SJGS Units 2 and 3 by the end of 2017 and the installation of selective non-catalytic reduction technology on Units 1 and 4 by the later of January 31, 2016 or 15 months after EPA approval of a revised State Implementation Plan. On May 12, 2014, the EPA filed in the Federal Register its proposal to withdraw the Federal Implementation Plan that addresses the NO_X BART and visibility transport requirements for the SJGS and to approve the State of New Mexico's revised State Implementation Plan for the SJGS. For further discussion of the ongoing environmental litigation involving the SJGS and Santa Clara's M-S-R PPA San Juan Unit No. 4 Interest and the status thereof, see "Litigation Affecting the Electric System" below.

M-S-R PPA Southwest Transmission Project. The Southwest Transmission Project consists of M-S-R PPA's acquisition of an interest in a 500 kV alternating current transmission project between the central Arizona area and the Los Angeles basin and certain other transmission facilities and arrangements to provide for the delivery of power and energy from the San Juan Unit No. 4 Interest to the M-S-R PPA members' systems in Northern California. Under the M-S-R PPA Agreement, Santa Clara is unconditionally obligated for 35% of the costs of the M-S-R PPA Southwest Transmission Project, subject to certain step up provisions. Transmission service from the

Midway Substation to Santa Clara's electric system is provided by the TANC Tesla–Midway Service. See "*—TANC Tesla—Midway Transmission Service*" above. M-S-R PPA financed the acquisition of the Southwest Transmission Project through the issuance of San Juan Project revenue bonds. See "Indebtedness; Joint Powers Agency Obligations" below.

Santa Clara is currently exploring layoff or sale options with regards to its 72 MW participation share of capacity in the Mead–Phoenix and Mead−Adelanto segments of the Southwest Transmission Project.

M-S-R PPA Purchased Power–Big Horn Projects. In 2005, M-S-R PPA entered into a series of power purchase agreements with Iberdrola Renewables, Inc. (formerly PPM Energy, Inc.) ("Iberdrola"), certain of which agreements have been assigned to Iberdrola's subsidiary, Big Horn I, LLC., for the purchase of energy from the Big Horn wind energy project (the "Big Horn I Project") located near the town of Bickleton, in Klickitat County, Washington. 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. For the fiscal year ended June 30, 2014, Santa Clara received 261.3 GWh of energy from the Big Horn I Project. 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.

M-S-R PPA subsequently negotiated a 25-year agreement with Iberdrola for the purchase of the output from a 50 MW expansion of the Big Horn I Project, the Big Horn II Project. The Big Horn II Project commenced operations on November 1, 2010. Santa Clara receives 35% of the output from this project, or approximately 17.5 MW of project capacity. For the fiscal year ended June 30, 2014, Santa Clara received 43.3 GWh of energy from the Big Horn II Project.

M-S-R Energy Authority – Gas Prepay. Santa Clara, along with Modesto and Redding, have also formed a California joint powers agency known as M-S-R Energy Authority ("M-S-R EA"). In 2009, Santa Clara participated in the M-S-R EA Gas Prepay Project. The 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. Under the terms of the Gas Supply Agreement, M-S-R EA bills 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, Modesto and Redding, is non-recourse to Santa Clara.

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 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, 2025, with Santa Clara receiving a 9.06592% "slice of the system" allocation from Western. 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 (9.06592%) of the costs associated with operating the CVP facilities. Under the successor agreement, Santa Clara's energy allocation dropped from pre-2005 levels of approximately 1,257 GWh to about 359 GWh per year delivered to Santa Clara based upon the hydrology of the CVP. For the fiscal year ended June 30, 2014, Santa Clara received 208.3 GWh of energy from Western. Santa Clara's Don Von Raesfeld power project, which commenced operation on March 22, 2005, was designed, in part, to offset the expected decrease in energy to be received from Western under the successor agreement beginning in 2005. See "Generating Facilities—*Don Von Raesfeld Power Plant*" above.

AES Seawest Purchased Power–Altamont Wind Project. In 2006, Santa Clara and AES Seawest Inc. entered into five-year land lease and power purchase agreements, whereby AES Seawest Inc. rents 691 acres in the Altamont area of Alameda County from Santa Clara and sells wind power generated on the rented land to Santa Clara. The AES Seawest Inc. arrangement adds approximately 1% of eligible renewable energy to Santa Clara's annual power mix. The windplant achieved commercial operation on May 3, 2007. AES Seawest Inc. operates and maintains the windplant facility which includes 200 small wind turbines (of which approximately 178 are operational), approximately 100 kW each. Santa Clara acts as the Scheduling Coordinator for the facility and schedules the output from the facility into the CAISO Participating Intermittent Resource Program, and the resulting energy is then traded to the NCPA Scheduling Coordinator portfolio which serves Santa Clara's load. For the fiscal year ended June 30, 2014, Santa Clara received 21.3 GWh of energy from the Altamont Wind Project. The AES Seawest Inc. power purchase agreements are scheduled to terminate on July 31, 2016.

Seattle City Light ("SCL") NCPA Exchange Agreement. In 2008, Santa Clara took over a share of the SCL-NCPA Exchange Agreement from certain other NCPA members. As a result, Santa Clara receives 32.6 MW from SCL during the months of June through October each year, and is obligated to provide 25 MW to SCL from December through mid-April each year. See "OTHER NCPA PROJECTS—Power Purchase and Other Contracts" in the front part of this Remarketing Memorandum.

G-2 Energy LLC – Wheatland Landfill. Santa Clara entered into a power purchase agreement for, and began taking delivery of energy in January 2009 from, a 1.6 MW landfill gas facility, G2, near Wheatland, California. For the fiscal year ended June 30, 2014, Santa Clara received 11.9 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. For the fiscal year ended June 30, 2014, Santa Clara received approximately 2,600 MWh of energy from the Ameresco Santa Clara landfill project. 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, CA. 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, CA. The Vasco Road landfill project became operational in February 2014. For the fiscal year ended June 30, 2014, Santa Clara received 4.8 GWh and 12.7 GWh for the Ameresco FWD and Ameresco VASCO landfill projects, respectively.

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 net MW solar photovoltaic-powered project in Kern County, California, which became operational in December 2013. For the fiscal year ended June 30, 2014, Santa Clara received 31.8 GWh of energy from Recurrent.

Manzana Wind. On February 14, 2012, Santa Clara entered into a 20-year power purchase agreement for 50 MW of the output from Iberdrola's Manzana Wind Power Project in Kern County, California, which began power deliveries in December 2012. For the fiscal year ended June 30, 2014, Santa Clara received approximately 143.9 GWh of energy from the Manzana Wind Power Project.

Friant 1. On May 15, 2012, Santa Clara entered into a power purchase agreement with the Friant Power Authority to purchase the output from three existing run-of-river hydroelectric facilities in Fresno County, the River Outlet (2 MW), the Friant-Kern (15 MW), and the Madera (8 MW). Santa Clara will receive energy deliveries starting January 1, 2016 through August 31, 2032.

Friant 2. On July 10, 2012, Santa Clara entered into a power purchase agreement with the Friant Power Authority to purchase the output from a new 7 MW run-of-river hydroelectric facility in Fresno County, the Quinten Luallen Power Plant. Energy deliveries are expected to begin on March 31, 2015 and end on August 31, 2032.

Tioga Solar. On February 2, 2012, Santa Clara entered into a 20-year power purchase agreement with Tioga Solar Santa Clara, LLC to develop, design, construct, own and operate a 400 kilowatt DC solar photovoltaic system on the roof of the Tasman Drive Parking Structure, which started power deliveries in June 2013. Santa Clara has the option to purchase the PV system at certain points during the contract term.

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: 72 MW Donnells Powerhouse, 25.7 MW Tulloch Powerhouse, 11.0 MW Beardsley Powerhouse, and 16.2 MW Southern Powerhouse. Power deliveries from Donnells, Tulloch, and Beardsley commenced on January 1, 2014. Power deliveries from Southern will commence on June 1, 2016. The agreement is scheduled to terminate on December 31, 2023. For the fiscal year ended June 30, 2014, Santa Clara received 4.7 GWh from Beardsley, 61.1 GWh from Donnells, and 51.6 GWh from Tulloch projects.

Future Power Supply Resources

Santa Clara's current resources are anticipated to provide Santa Clara with sufficient capacity reserves. In addition to its participation in NCPA's Lodi Energy Center Project completed in 2012, Santa Clara will generally meet additional long-term energy and capacity needs through long-term agreements with creditworthy energy providers. Santa Clara will continue to use portfolio and risk management strategies to manage its performance. See "Wholesale Power Trading" below.

Wholesale Power Trading

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 power trading is to optimize the value of the utility's assets and cost-effectively serve its retail load. For fiscal years ended June 30, 2009, 2010, 2011, 2012 and 2013 net trading revenues (wholesale power sales revenues less wholesale power purchase costs) were approximately $(8.4) million, $(5.9) million, $(0.7) million, $(3.0) million and $(2.4) million, respectively. The results in fiscal years 2008-09 through 2012-13 are primarily related to wholesale purchases intended for retail use that, due to recorded sales falling short of those forecasted and generation from lower costs resources subsequently becoming available, were sold back to the market at prices lower than the original purchase prices. As prices for natural gas have continued to decline, since their peak in mid-2008, additional long-term gas supply contracts have been entered into by SVP.

The Santa Clara City Council has approved a 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 Santa Clara City Manager, the Director of Finance, the Director of Electric Utility 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.

Renewable Energy and Energy Efficiency

A significant portion of the energy received by Santa Clara customers comes from renewable energy. Santa Clara's power mix in calendar year 2013 consisted of 24.2% eligible renewable resources. When large hydroelectric resources are included, Santa Clara's power mix consisted of 41.9% renewable and large hydroelectric. On December 6, 2011, the Santa Clara City Council adopted revisions to Santa Clara's Environmental Stewardship and Renewable Portfolio Standard ("RPS") Policy Statement, and adopted a new RPS Enforcement Program, to conform with the standards and timetable set forth in SBX1 2, signed by the Governor on April 12, 2011. Essentially, the revised policy expands Santa Clara's commitment to renewable energy by targeting 33% of Santa Clara's energy needs to be served by renewable resources (not including "large hydro") by 2020. See "DEVELOPMENTS IN THE CALIFORNIA ENERGY MARKETS—State Legislation—*Renewable Portfolio Standards*" in the front part of this Remarketing Memorandum.

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 $8 million per year. Residential programs include rate assistance for low-income customers, energy efficiency rebates (refrigerators, LED light bulbs, electric clothes dryers, electric heat pump water heaters, and ceiling fans), solar electric installations, 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 (lighting, air conditioning systems, chillers, programmable thermostats, washing machines, Uninterruptible Power Supplies, control systems, new construction, photovoltaic systems and customized installations), and design and construction assistance. Over 328.9 million kilowatt hours in net cumulative "first year" savings have been achieved since 1998.

Interconnections, Transmission 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 Santa Clara-owned 115 kV receiving stations – Northern Receiving Station ("NRS") and Kifer Receiving Station ("KRS"), each located within Santa Clara's 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 19.3 square miles), which includes approximately 27 miles of 60 kV power lines, approximately 500 miles of 12 kV distribution lines (approximately 64% of which are underground), and 26 stations. Santa Clara's electric system experiences approximately 0.5 to 1.5 hours of outage time per customer per year. 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.

Employees

As of January 1, 2014, Santa Clara had approximately 142 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 Santa Clara employees' associations, in matters pertaining to wages, benefits and working conditions. The current labor agreements with the various employee associations went into effect December 22, 2013 and will expire on December 19, 2015. There have been no strikes or other union work stoppages at the City of Santa Clara, including its electric utility department.

The City of 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, which is a public employee retirement system that acts as a common investment and administrative agent for participating public entities within the State of California. CalPERS offers a menu of benefit provisions and other requirements that are established by State statutes within the Public Employee Retirement law. The City of Santa Clara selects optional benefit provisions from the benefit menu by contract with CalPERS and adopts those benefits through local ordinance. CalPERS issues a separate comprehensive annual financial report. Copies of the CalPERS annual financial report may be obtained from the CalPERS Executive Office, 400 Q Street, Sacramento, California 95814 or from the CalPERS website at *www.calpers.ca.gov*.

All electric utility department employees are covered by the City's Miscellaneous Plan which provides retirement and disability benefits, annual cost-of-living adjustments and death benefits to plan members and beneficiaries. All permanent (full-time and part-time) and eligible "as-needed" hourly City employees are required to participate in CalPERS. The cost of the pension is funded through bi-weekly contributions from employees and from employer contributions by the City of Santa Clara. The City of Santa Clara has funded 100% of its actuarially determined contribution requirement for each of the fiscal years ended June 30, 2011 through 2013 (which requirement totaled $20,485,590 for fiscal year 2010-11, $23,711,219 for fiscal year 2011-12 and $24,294,443 for fiscal year 2012-13 for both Miscellaneous Plan and Safety Plan members). Of such amounts, $2,613,617 was funded by the Electric Utility for fiscal year 2010-11, $3,230,413 was funded by the Electric Utility for fiscal year 2011-12 and $3,414,393 was funded by the Electric Utility for fiscal year 2012-13. As of June 30, 2012 (the latest date for which actuarial information is available), the total actuarial accrued liability for the City of Santa Clara was $529,444,627 for the Miscellaneous Plan, the actuarial value of plan assets was $389,285,652, and the Miscellaneous Plan had an unfunded liability of $140,158,975, representing a funded ratio of 73.5%. The portion of the plan's assets allocable to the Electric Utility employees, which is part of the City of Santa Clara's liability pool, has not been separately calculated.

The actuarial value of plan assets is determined utilizing a smoothing technique in order to dampen the effect of short term market value fluctuations on employer contribution rates. Under the smoothing technique, an expected value of assets is computed by bringing forth the prior year's actuarial value of assets and the contributions received and benefits paid during the year at the assumed actuarial rate of return. The actuarial value of assets is then computed as the expected value of assets plus 1/15th of the difference between the market value of assets and the expected value of assets as of the valuation date. In no case will the actuarial value of assets be less than 80% or more than 120% of the actual market value of assets. As of June 30, 2012, the market value of the plan assets (with receivables) was $324,835,991 (representing a funded status based on market valuation of 61.4%).

On March 14, 2012, the CalPERS Board voted to reduce the discount rate, which is attributable to its expected price inflation and rate of return and investment rate of return (net of administrative expenses), from 7.75% to 7.5%. As a result, the amounts of CalPERS member public agency contributions will increase by 1% to 2% for Miscellaneous Plans beginning in fiscal year 2013-14. On September 12, 2012, the State of California passed Assembly Bill 340, the Public Employees' Pension Reform Act ("PEPRA"). PEPRA implemented new benefit formulas and final compensation period, as well as new contribution requirements for new employees hired on or after January 1, 2013 who meet the definition of new member under PEPRA.

On April 17, 2013 the CalPERS Board of Administration approved new actuarial policies aimed at fully funding the pension system's obligations within 30 years. The new policies include a rate-smoothing method with a 30-year fixed amortization period for gains and losses. CalPERS announced that, based on investment return simulations performed for the next 30 years, increasing contributions more rapidly in the short term is expected to result in almost a 25% improvement in funded status over a 30-year-period. The new amortization schedule will be used to set contribution rates for public agency employers in the State beginning in the 2015-16 fiscal year. This delay is intended to allow the impact of the changes to be built into the projection of employer contribution rates and afford employers with additional time to adjust to the changes.

According to CalPERS, the new policies will result in an increased likelihood of higher peak employer contribution levels in the future but will not significantly increase average contribution levels. The median employer contribution rate over the next four years is expected to be higher. In the long-term, however, higher funded levels may result in lower employer contributions.

On February 20, 2014, the CalPERS Board of Administration adopted new mortality and retirement assumptions as part of a regular review of demographic experience. Key assumption changes included longer post-retirement life expectancy and earlier retirement ages. The impact of the assumption changes will be phased in over five years, with a twenty-year amortization, beginning in the 2016-17 fiscal year. CalPERS has estimated that the adoption of the new assumptions will increase employer contribution rates (as a percentage of payroll) for most Miscellaneous Plans in the range of by 0.4% to 1.9% in the 2016-17 fiscal year and in the range of by 1.0% to 6.7% by 2020-21, depending on the benefit formula applicable to active members.

In addition, the City of Santa Clara provides certain post-employment benefits other than pensions (OPEB) to city employees, including those assigned to the electric utility department, who retire from the City of Santa Clara, through a single-employer defined benefit program established by the Santa Clara City Council in fiscal year 2007-08 which provides reimbursements to retirees for certain qualified expenses, subject to certain annual maximum reimbursement amounts. In fiscal year 2007-08, the City of Santa Clara established an irrevocable exclusive single-employer benefit trust which is administered by Public Agency Retirement Services.

The annual required contributions ("ARC") to the OPEB Plan are based on actuarial valuations. The contribution requirements of the ARC are established and may be amended by the City Council. Plan members do not make contributions to the plan; the plan is entirely funded by employer contributions. The City of Santa Clara's annual OPEB costs is calculated based upon the ARC, an amount actuarially determined in accordance with the parameters of Governmental Accounting Standards Board Statement No. 45. The ARC represents the level of funding that, if paid on an ongoing basis, is projected to cover normal costs each year and amortize any unfunded actuarial liabilities over 30 years. The City of Santa Clara has funded 100% of its annual OPEB cost (equal to the ARC) for each of the fiscal years ended June 30, 2011 through 2013. The actuarially determined contribution requirement for the OPEB plan totaled $2,149,000 for fiscal year 2010-11, $2,369,000 for fiscal year 2011-12 and $2,445,000 for fiscal year 2012-13. Of such amounts, approximately $249,570 was funded by the Electric Utility for fiscal year 2010-11, approximately $195,360 was funded by the Electric Utility for fiscal year 2011-12 and approximately $350,064 was funded by the Electric Utility for fiscal year 2012-13. As of June 30, 2012 (the latest date for which actuarial information is available), the total actuarial accrued liability for the City of Santa Clara OPEB plan was $36,473,000, the actuarial value of plan assets was $9,129,000, and the unfunded actuarial accrued liability was $27,344,000, representing a funded ratio of 25.0%.

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's comprehensive annual financial reports, which may be obtained at *http://www.santaclaraca.gov*.

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 are adopted by the Santa Clara City Council. The authority of Santa Clara to impose and collect rates and charges for electric power and energy is not subject to the regulatory jurisdiction of the California Public Utilities Commission (the "CPUC") or any other regulatory authority.

The following table summarizes a history of Santa Clara's electric rate increases over the last seven years.

CITY OF SANTA CLARA
ELECTRIC UTILITY DEPARTMENT
HISTORY OF ELECTRIC RATE CHANGES

Date	Percent Change
January 1, 2014	5.00%
January 1, 2013	0.00
January 1, 2012	0.00
January 1, 2011	7.00
January 1, 2010	7.00
January 1, 2009	3.00
January 1, 2008	3.00

Source: City of Santa Clara.

Largest Customers

The ten largest customers of Santa Clara's electric utility department, in terms of kWh sales for the fiscal year ended June 30, 2014 accounted for 41.5% of total kWh sales and 36.9% of revenues. Santa Clara is heavily dependent upon its industrial customers, which comprise approximately 88% of its load and approximately 87% of its revenues from the sale of energy (in fiscal year 2013-14). 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 entered into power purchase contracts with a number of its largest customers. Currently, 16 customers, representing approximately 49% of Santa Clara's electric utility load and approximately 44% of annual sales revenues, are under contract. The contracts have varied terms, with expirations ranging from 2014 through 2016. No existing customer contract has a term exceeding five years.

Customers, Energy Sales, Revenues and Demand

The average number of customers, kWh sales and revenues derived from sales, by classification of service, and peak demand during the five fiscal years 2009-10 through 2013-14, are listed below.

CITY OF SANTA CLARA
ELECTRIC UTILITY DEPARTMENT
CUSTOMERS, SALES, REVENUES AND DEMAND
(Fiscal Year Ended June 30)

	2010	2011	2012	2013	2014*
Number of Customers:					
Residential	43,989	44,086	44,344	44,415	44,629
Commercial	5,957	6,030	6,142	6,175	6,191
Industrial	1,860	1,820	1,780	1,754	1,758
Other	558	559	559	560	561
Total	52,364	52,495	52,825	52,904	53,139
Kilowatt-hour Sales (000):					
Residential	247,202	242,431	244,212	237,387	233,847
Commercial	84,660	87,830	92,868	92,284	91,833
Industrial	2,411,087	2,470,311	2,545,830	2,594,428	2,651,757
Other	21,247	20,467	19,967	20,966	20,561
Total	2,764,196	2,821,039	2,902,877	2,945,065	2,997,998
Charges from Sale of Energy (000)(1):					
Residential	$ 23,418	$ 24,572	$ 25,446	$ 24,795	$ 25,078
Commercial	11,265	12,474	13,562	13,583	13,771
Industrial	222,071	245,356	261,934	264,806	274,402
Other	2,206	2,195	2,345	2,416	2,435
Total(2)	$258,960	$284,597	$303,287	$305,600	$315,686
Peak Demand (MW)	459.8	471.4	463.0	471.1	478.9

* Preliminary data.
(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.

Capital Requirements

Santa Clara expects net capital requirements for the next five fiscal years to aggregate up to $92.7 million. Such improvements include distribution system improvements and replacements of approximately $75.4 million, 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. They are expected to be financed through a combination of load development fees, funds from Santa Clara's available cash reserves, proceeds of a direct loan financing (described under "Indebtedness; Joint Powers Agency Obligations" below) and electric revenues.

This forecast assumes capital expenditures for substation upgrades, equipment replacement, new technology deployment, and economic development projects. Included in these expenditures are two new projects, the Northern Receiving Station Phase Shift Transformer and the SVP Fiber Optic Expansion Project, which will result in reduced operating costs as well as improving the utility's communications infrastructure for more robust service and business opportunities, and are anticipated to be funded by electric customer service charges.

On February 22, 2011, the City Council authorized the execution of a joint powers agreement with the City redevelopment agency which authorized the creation of the Santa Clara Stadium Authority. This joint powers agency is leasing City property to construct a football stadium facility in the vicinity of Great America Parkway and Tasman Drive in the City of Santa Clara for the relocation of the San Francisco 49ers professional football team.

Construction of the stadium facility was completed in July 2014. In connection with the stadium project, the Electric Utility relocated its Tasman substation, originally located near the stadium site. The cost of this substation relocation was approximately $20 million (which cost was funded from available cash reserves of the utility).

In other ongoing capital projects, the Electric Utility continues to improve, demonstrate, and implement new technologies to support the power grid of the future. Some key projects being deployed in this area are the continuing development of an Advanced Metering Infrastructure Project, the ongoing Operational and Technology Project, updating the power scheduling and back office systems required to schedule, track and settle power purchase, sales and delivery transactions, and the improvement of the electric system cyber security as required by mandatory federal reliability standards.

The capital budget reflects the Electric Utility's focus on system improvements including substation upgrades, equipment replacement, new technology deployment, and economic development projects. The proposed budget supports on-going capacity expansion of the system to meet customer needs, enhanced reliability, and maintenance of the current high level of service. These investments are critical for meeting the energy needs of existing customers, and those of new and expanding businesses in the City of Santa Clara, a key component to the City's economic development programs.

Indebtedness; Joint Powers Agency Obligations

Electric Revenue Bonds. As of June 30, 2014, Santa Clara had outstanding senior lien electric revenue bonds in the aggregate principal amount of $194.85 million, payable from net revenues of the electric system. Such outstanding electric revenue bonds are comprised of $75.640 million aggregate principal amount of outstanding Electric Revenue Refunding Bonds, Series 2008 B (the "Series 2008 B Bonds"), $54.830 million aggregate principal amount of Electric Revenue Refunding Bonds, Series 2011 A and $64.380 million aggregate principal amount of Electric Revenue Refunding Bonds, Series 2013 A.

In addition to the outstanding electric revenue bonds, Santa Clara has entered into a Loan Agreement, dated as of June 16, 2014 (the "Loan Agreement"), with Banc of America Preferred Funding Corporation ("BofA") providing for a direct loan (the "Loan") from BofA to Santa Clara by BofA in an aggregate amount of approximately $31.2 million, to be made in certain installments through January 1, 2016. Santa Clara's obligation to make repayment of the Loan to BofA is evidenced by a subordinated electric system revenue bond of Santa Clara (the "Subordinate Electric Revenue Bond"), payable from net revenues of the electric system on a basis junior and subordinate to the payment of Santa Clara's outstanding electric revenue bonds. Principal of the Loan is payable in annual installments, commencing on July 1, 2016 and ending on July 1, 2024. The occurrence of an event of default by Santa Clara under the Loan Agreement may result in an increase in the interest rate payable by the City with respect to the Subordinated Electric Revenue Bond and the Loan evidenced thereby and/or an acceleration in the payment of the principal amount of such Subordinated Electric Revenue Bond and the Loan evidenced thereby in accordance with the terms of the Loan Agreement.

Santa Clara's Series 2008 B Bonds are variable rate obligations secured by a letter of credit. The letter of credit for the Series 2008 B Bonds has been provided by The Bank of Tokyo-Mitsubishi UFJ, Ltd., acting through it New York Branch ("The Bank of Tokyo"), and has a scheduled expiration date of October 30, 2015. Santa Clara has entered into a reimbursement agreement with The Bank of Tokyo, pursuant to which it is obligated to repay the bank for amounts drawn under the letter of credit. The repayment obligations of Santa Clara under the reimbursement agreement are payable on a parity with Santa Clara's electric revenue bonds. The interest rate payable by Santa Clara for unreimbursed draws under the letters of credit may be considerably higher than the interest rate on the bonds. In the event of a significant unreimbursed draw on the letter of credit due to the unsuccessful remarketing of the Series 2008 B Bonds, Santa Clara may attempt in such event to refinance the bonds to avoid this additional debt burden, however, in such event, there can be no assurance that Santa Clara will have access to the debt markets.

Prior to the issuance of the Series 2008 B Bonds, Santa Clara entered into an interest rate swap agreement (the "Swap Agreement") with Bear Stearns Capital Markets Inc., which agreement has been novated to JPMorgan Chase Bank, N.A. (the "Swap Provider"). Under the Swap Agreement, Santa Clara is obligated to make payments to the Swap Provider calculated on the basis of a fixed rate of 3.470% while it is to receive from the Swap Provider payments based upon 65% of the one month London InterBank Offering Rate. Santa Clara's obligation to make any net regularly scheduled payments due to the Swap Provider under the Swap Agreement is payable from net revenues of the electric system on a parity with its outstanding electric revenue bonds. There is no guarantee that the floating rate payable to Santa Clara pursuant to the Swap Agreement will match the variable interest rate on the associated Series 2008 B Bonds at all times or at any time. Under certain circumstances, the Swap Provider may be obligated to make a payment to Santa Clara under the Swap Agreement that is less than the interest due on the associated Series 2008 B Bonds. In such event, Santa Clara would be obligated to pay such insufficiency from net revenues of the Electric Utility on a parity with Santa Clara's outstanding electric revenue bonds. Under certain circumstances, the Swap Agreement may be terminated and Santa Clara may be required to make a termination payment to the Swap Provider. Any such termination payment owed by Santa Clara would be payable from net revenues of the electric system subordinate to Santa Clara's outstanding electric revenue bonds.

Pursuant to the terms of the Swap Agreement, Santa Clara is required to post collateral in favor of the Swap Provider to the extent that Santa Clara's total exposure for termination payments to the Swap Provider exceeds the threshold amount specified in the Swap Agreement. The applicable collateral posting threshold amounts specified in the Swap Agreement would be lower in the event certain ratings assigned to Santa Clara's electric revenue bonds were to be revised downward or withdrawn. In the case of a ratings withdrawal or significant downward rating revision, such decline in the applicable threshold amount could significantly increase Santa Clara's collateral posting obligation thereunder. If the ratings assigned to Santa Clara's electric revenue bonds are revised upward, the amount of collateral required to be posted by Santa Clara under the Swap Agreement could be reduced. Under the terms of the Swap Agreement, the Swap Provider is required to release collateral to Santa Clara as market conditions become favorable to Santa Clara and may be required to post collateral for the benefit of Santa Clara to the extent that such Swap Provider's total exposure for termination payments to Santa Clara exceeds the threshold amount specified in the Swap Agreement. As of June 30, 2014, Santa Clara had $4.1 million in collateral posted in favor of the Swap Provider. The highest amount of collateral Santa Clara has been required to post to the Swap Provider on any date has been approximately $11.0 million. The amount of collateral varies from time to time due primarily to interest rate movements and can change significantly over a short period of time. In the future, Santa Clara may be required to post additional collateral, or may be entitled to a reduction or return of the required collateral amount. Collateral deposited by Santa Clara is held by the Swap Provider or an agent therefor. A bankruptcy of the Swap Provider holding collateral posted by Santa Clara could adversely affect the return of the collateral to Santa Clara. Moreover, posting collateral limits the electric utility's liquidity. If collateral requirements increase significantly, the electric utility's liquidity may be adversely affected.

Joint Powers Agency Obligations. As previously discussed, Santa Clara participates in several joint powers agencies, including NCPA, TANC, 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 NCPA, TANC 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 NCPA, TANC 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 "Joint Powers Agency Resources–*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 NCPA, TANC and M-S-R PPA projects in which it participates are shown in the table on the following page.

CITY OF SANTA CLARA
ELECTRIC UTILITY DEPARTMENT
OUTSTANDING DEBT OF JOINT POWERS AGENCIES
(as of June 30, 2014)
(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	$ 265.0	35.00%	$92.8
Southwest Transmission Project	23.4	35.00	8.2
NCPA			
Geothermal Project	41.3	44.39	18.3
Calaveras Hydroelectric Project	401.2	37.02(3)	152.5 (3)
Lodi Energy Center, Issue One	245.7	46.16	113.4
TANC			
Bonds	314.2	20.84(4)	66.0(4)
TOTAL*	$1,290.8		$451.2

* Columns may not add to totals due to independent rounding.

(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 upon default of another 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) Includes 1.16% additional share purchased from other NCPA participants. In addition, Santa Clara's actual payments represent approximately 38.0% of outstanding debt service as a result of credit to non-participating members with respect to portion of debt obligation.

(4) As described herein, Santa Clara's actual 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. As described herein, effective July 1, 2014, Santa Clara has entered into an agreement to layoff to other TANC Member-Participants approximately 53% of its COTP interest for a term of 25 years which will effectively reduce Santa Clara's payment obligation for the debt to approximately 10.14%. Santa Clara remains contractually obligated for its full participation share.

Source: City of Santa Clara Electric Utility Department.

For the fiscal year ended June 30, 2014, Santa Clara's obligation for debt service on its joint powers agency aggregated obligations was approximately $47.0 million. Debt service on joint powers agency obligations is expected to range in each fiscal year through 2039-40 from a high of approximately $42.4 million to a low of approximately $7.7 million. 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. In connection with certain of such joint power agency obligations, the respective joint powers agency has entered into interest rate swap agreements relating thereto for the purposes of substantially fixing the interest cost with respect thereto. There is no guarantee that the floating rate payable to the respective joint powers agency pursuant to each of the interest rate swap agreements relating thereto 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 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 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 Santa Clara).

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 City General Fund each year as a contribution in lieu of taxes.

The following table sets out the transfers from the electric utility to the City General Fund for the five fiscal years 2008-09 through 2012-13.

CITY OF SANTA CLARA
ELECTRIC UTILITY DEPARTMENT
TRANSFERS TO THE GENERAL FUND
(Dollar Amounts in Thousands)

Fiscal Year	Transfer Amount
2008-09	$13,037
2009-10	13,448
2010-11	14,913
2011-12	15,343
2012-13	15,219

Source: City of Santa Clara.

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) as described below.

In addition to the Cost Reduction Fund, 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, 2013, approximately $102.26 million was on deposit in the Rate Stabilization Fund (including approximately $77.26 million on deposit in the Cost Reduction Account therein). In addition, as of June 30, 2013, Santa Clara had unrestricted operating cash reserves of $82.46 million, as well as $45.85 million of cash reserves designated for construction purposes. Thus, as of June 30, 2013, Santa Clara's electric utility had restricted and unrestricted cash reserves totaling approximately $230.57 million.

Collectively, these reserves are designed to help insulate Santa Clara from market volatility. In addition, Santa Clara's bond indenture permits the use of unrestricted cash balances and reserves (including, prior to December 31, 2010, the Cost Reduction Fund and the Rate Stabilization Fund, and subsequent to December 31, 2010, the Rate Stabilization Fund) to satisfy Santa Clara's rate covenants with its bond holders. In fiscal year 2009-10 approximately $6.24 million was transferred from the Rate Stabilization Fund related to operating expenses. For fiscal years 2010-11 and 2011-12, Santa Clara did not make any withdrawals from the Rate Stabilization Fund (Cost

Reduction Account) for operating expenses or non-bond funded capital expenditures and improvements in such fiscal year. In fiscal year 2012-13, approximately $7.43 million was transferred from the Rate Stabilization Fund related to operating expenses.

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 (including the Cost Reduction Account). In order to maintain this minimum target balance, Santa Clara adopted a 7% electric rate increase in January 2010, a 7% electric rate increase in January 2011, and a 5% electric rate increase in January 2014. Due to the ongoing drought and increases in CAISO transmission costs, Santa Clara is anticipating additional rate increases will be needed to cover future operating expenses and to restore the Cost Reduction Account balance (now a part of the Rate Stabilization Fund) to the $120 million targeted level within the next few years. See "Condensed Operating Results and Selected Balance Sheet Information" below and "Rates and Charges" above. It is important to note that the impact of such increase or increases could be affected by future operating conditions, including factors outside the control of Santa Clara.

Service Area

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, 2013.

CITY OF SANTA CLARA
LARGEST EMPLOYERS

Employer	Business	Number of Employees
Applied Materials, Inc.	Nano Technology Mfg Services	8,500
Intel Corporation	Semiconductor Devices (Mfg.)	7,001
California's Great America	Amusement Park	2,500
Avaya Inc.	Software	2,000
City of Santa Clara	Local Government	1,412
EMC Corporation	Semiconductors	1,338
Macy's	Retail	1,200
Santa Clara University	Higher Education	1,200
ON Semiconductor Corporation	Semiconductor Devices (Mfg.)	1,200

Source. City of Santa Clara.

A five-year history of building permits in Santa Clara is as follows:

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CITY OF SANTA CLARA
Building Permit Valuations
Calendar years 2009 through 2013
(In Thousands)

	2009	2010	2011	2012	2013
Residential Valuation					
Single Family	$ 1,010	$3,550	$7,472	$21,699	$19,908
Multi-Family	11,840	1,897	1,952	10,302	53,717
Total	$12,850	$5,447	$9,424	$32,001	$73,625
Non-Residential					
New Commercial	$ 6,375	$ 0	$ 21,435	$160,458	$ 53,113
New Industrial	0	22,000	61,100	6,457	1,215
Other	11,858	1,905	16,387	8,585	2,388
Alterations/Additions	81,011	165,315	140,946	91,581	264,193
Total	$99,244	$189,220	$239,868	$267,081	$320,909
New Dwelling Units					
Single Family	9	18	35	68	74
Multi-Family	60	15	127	75	422
Total	69	33	162	143	496

Source: Construction Industry Research Board.

Population

Shown below is certain population data for Santa Clara, the County of Santa Clara and the State of California:

CITY OF SANTA CLARA, COUNTY OF SANTA CLARA,
STATE OF CALIFORNIA POPULATION
(1970-2010 as of April 1; 2011-2014 as of January 1)

	City of Santa Clara	County of Santa Clara	State of California
1970	86,118	1,065,313	19,971,069
1980	87,746	1,295,071	23,668,562
1990	93,613	1,497,577	29,760,021
2000	102,361	1,682,585	33,873,086
2010	116,468	1,781,642	37,253,956
2011	117,998	1,794,337	37,427,946
2012	118,632	1,813,702	37,668,804
2013	120,196	1,840,895	37,984,138
2014	121,229	1,868,558	38,340,074

Sources: U.S. Bureau of Census and California State Department of Finance.

Transportation and Educational Facilities

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.

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.

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 the Third Phase Agreement.

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

Present lawsuits and other claims against Santa Clara's electric utility department are incidental to the ordinary course of operations of the electric utility department and are largely covered by Santa Clara's 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 the financial position of Santa Clara.

San Juan Environmental Litigation. The EPA has established rules addressing regional haze (*i.e.*, visibility impairment caused by cumulative air pollutant emissions from numerous sources over a wide geographic area). The rules call for all states to establish goals and emission reduction strategies for improving visibility in national parks and wilderness areas. The rules require Best Available Retrofit Technology ("BART") to be considered as a control measure on specific categories of certain major stationary sources of haze-producing pollutants in existence prior to the enactment in 1977 of the Clean Air Act amendments addressing regional haze. If a source is found to be BART-eligible, a determination of the source's contribution to visibility impairment and the resulting emission reductions from the application of BART is conducted.

The SJGS is a source that is subject to the statutory obligations of the Clean Air Act to reduce visibility impacts. The State of New Mexico submitted a State Implementation Plan ("SIP") on the regional haze and interstate transport elements of the visibility rules for review by EPA in June 2011. The SIP found that BART to reduce NOx emissions from the San Juan Generating Station is selective non-catalytic reduction technology ("SNCR"). Nevertheless, in August 2011, the EPA published its Federal Implementation Plan ("FIP"), stating that it was required to do so by virtue of a consent decree it had entered into with an environmental group in litigation concerning the interstate transport requirements of the Clean Air Act. The FIP included a regional haze BART determination for the SJGS that required installation of selective catalytic reduction technology ("SCR") with stringent NOx emission limits on all four units by September 21, 2016. PNM, the Governor of New Mexico, and the New Mexico Environment Department (the "NMED") petitioned the Tenth Circuit to review the EPA's decision and requested the EPA to reconsider its decision. The Tenth Circuit denied petitions to stay the effective date of the rule on March 1, 2012. These parties also formally asked the EPA to stay the effective date of the rule. Several environmental groups have intervened in support of the EPA. WildEarth Guardians, an environmental group, also filed an action to challenge the EPA's rule in the Tenth Circuit, seeking to shorten the rule's compliance period from five years to three years and PNM has intervened in this action. Oral arguments on the merits of the FIP challenges were held in October 2012 in the Tenth Circuit. In accordance with the court's order, the parties have filed supplemental information. In litigation involving several environmental groups, the United States District Court for the District of Columbia entered a consent decree, which, as amended, required the EPA to issue a final rulemaking on New Mexico's regional haze SIP by November 15, 2012. The EPA approved all components of the SIP, except for the NOx BART determination for the SJGS. With respect to that element of the SIP, the EPA determined that with the FIP in place, it had met its obligation under the consent decree.

Because the unchanged compliance deadline of the FIP required PNM to continue to take steps to commence installation of SCRs at the SJGS, PNM entered into a contract in October 2012 with an engineering, procurement, and construction contractor to install SCRs on behalf of the San Juan Generating Station owners, including M-S-R PPA. The construction contract, which includes termination provisions in the event that SCRs are determined in the future to be unnecessary, has been suspended through November 1, 2014. At the time of execution of the contract, PNM estimated the total cost to install SCRs on all four units of the SJGS to be between approximately $824 million and $910 million, although final costs would be refined through an "open book" subcontractor bidding process. Also, PNM had previously indicated it estimated the cost of SNCRs on all four units of SJGS to be between approximately $85 million and $90 million based on a conceptual design study. Along with the SNCR installation, additional equipment would be required to be installed to meet certain federal air quality standards, the cost of which had been estimated to total between approximately $105 million and $110 million for all four units of the SJGS.

During 2012 and early 2013, PNM, as the operating agent for the SJGS, engaged in discussions with the NMED and the EPA regarding an alternative to the FIP and SIP. Following approval by a majority of the other SJGS owners, PNM, the NMED and the EPA agreed on February 15, 2013 to pursue a revised plan that could provide a new BART path to comply with federal visibility rules at the SJGS, subject to approval by the New Mexico Environmental Improvement Board (the "EIB") and the EPA. The terms of this nonbinding agreement were to result in the retirement of the SJGS Units 2 and 3 by the end of 2017 and the installation of SNCRs on Units 1 and 4 by the later of January 31, 2016 or 15 months after EPA approval of a revised SIP.

The State of New Mexico submitted SIP revisions on October 7, 2013 and November 5, 2013, pursuant to this agreement. The revised SIP reflects the terms of the nonbinding agreement among PNM, the NMED and the EPA to address the regional haze requirements applicable to the SJGS. If fully approved by the EPA, the revised SIP would supersede the State of New Mexico's previous NO_X BART determination included in the earlier SIP in 2011.

Following that action, on May 12, 2014, the EPA filed in the Federal Register its proposal to withdraw the FIP that addresses the NO_X BART and visibility transport requirements for the SJGS and to approve the State of New Mexico's SIP as revised in 2013, based upon a determination that they adequately address the "good neighbor" provisions of the haze regulation. Parties were given 30 days to comment (*i.e.*, by June 11, 2014).

Due to the long lead times on certain equipment purchases, PNM has taken steps to prepare for the potential installation of SNCRs on Units 1 and 4 as contemplated by the revised SIP. In April 2013, PNM issued a request for proposals for SNCR system design and technology. In May 2013, PNM entered into an SNCR equipment and related services contract with an SNCR technology provider, and has entered into a construction contract for Unit 1. PNM, as operating agent, presented the SNCR project to the participants in Unit 1 and Unit 4 for approval in late October 2013. The project was approved for Unit 1, but the Unit 4 project did not obtain the required percentage of votes for approval. Certain other capital projects related to Unit 4 were also not approved by the participants. The San Juan Project Participation Agreement provides that PNM is authorized and obligated to take reasonable and prudent actions necessary for the successful and proper operation of the SJGS pending resolution by the participants.

In connection with the implementation of the revised plan and retirement of the SJGS Units 2 and 3, certain SJGS participants have expressed a desire to exit their ownership in the plant.

On June 20, 2014, representatives of the nine San Juan Generating Station owners reached a non-binding agreement in principle on the ownership restructuring of the San Juan Generating Station due to the proposed retirement of Units 2 and 3 by December 31, 2017 as necessary to implement the revised SIP. The participants' non-binding agreement on the restructuring of the ownership of the San Juan Generating Station has been memorialized in the form of (i) a Resolution of the San Juan Generating Station Coordination Committee Regarding San Juan Project Restructuring (the "San Juan Resolution") and (ii) the San Juan Generating Station Restructuring Non-Binding Term Sheet of Remaining Participants (the "Remaining Participants' Term Sheet"). Under the San Juan Resolution, the owners that that would exit active participation in the San Juan Generating Station effective December 31, 2017 would include, in Unit 4, M-S-R PPA and the City of Anaheim. The ownership shares of M-S-R PPA and the City of Anaheim are proposed to be acquired by PNM and the City of Farmington, New Mexico.

The San Juan Resolution was unanimously approved by the San Juan Coordination Committee on June 26, 2014. The Remaining Participants' Term Sheet was also approved on June 26, 2014 by the San Juan Generating Station owners that are expected to retain an interest in the ongoing operation of one or more units of the SJGS. A number of regulatory approvals are required in order to implement the proposed ownership restructuring of the SJGS as contemplated by the San Juan Resolution and the Remaining Participants' Term Sheet. In addition, various amendments are likely to be required to the existing San Juan-related agreements. Further, details as to the allocation of ongoing responsibility for decommissioning costs and any environmental liabilities, among other things, remain to be determined. As noted above, the San Juan Resolution and Remaining Participants' Term Sheet are non-binding. The proposed ownership restructuring of the SJGS pursuant to the San Juan Resolution and the Remaining Participants' Term Sheet is subject to and conditioned upon execution of final definitive agreements and receipt of necessary regulatory approvals.

Santa Clara is unable to predict the final outcome of the environmental proceedings relating to the SJGS and their impact on its M-S-R PPA San Juan Unit No. 4 Interest. Santa Clara is further unable to predict whether any proposed restructuring of the ownership of the SJGS, including the currently proposed restructuring whereby M-S-R PPA would divest its ongoing participation in Unit 4 effective December 31, 2017, can be implemented. Santa Clara and the other M-S-R PPA members continue to evaluate their options and the economics of continued participation in San Juan. See "Joint Powers Agency Resources–*M-S-R PPA Purchased Power – San Juan*."

Condensed Operating Results and Selected Balance Sheet Information

The following table sets forth summaries of income and selected balance sheet information of Santa Clara's electric utility for the five fiscal years 2008-09 through 2012-13. The information for the fiscal years ended June 30, 2009 through June 30, 2013 was prepared by Santa Clara on the basis of its audited financial statements for such years.

CITY OF SANTA CLARA
ELECTRIC UTILITY DEPARTMENT
SUMMARY OF FINANCIAL OPERATING RESULTS*
($ in 000s)

	Fiscal Year Ending June 30,				
	2009	**2010**	**2011**	**2012**	**2013**
Summary of Income					
Operating Revenues[1]	$243,889	$252,518	$277,769	$297,644	$298,751
Operating Expenses:					
Salaries, Wages and Benefits	18,402	20,060	20,040	20,994	21,294
Materials, Supplies and Services[2]	263,690	224,253	226,211	227,351	255,078
Depreciation	17,867	17,864	18,608	19,214	19,402
Total Operating Expenses	$299,959	$262,177	$264,859	$267,559	$295,774
Operating Income (Loss)	(56,071)	(9,659)	12,910	30,085	2,977
Other Income[3]	34,354	26,921	25,577	21,110	16,029
Interest Expense	(9,860)	(8,547)	(9,313)	(11,083)	(11,075)
Wholesale Power Sales	102,480	67,840	50,124	29,149	22,296
Wholesale Power Purchases	(110,879)	(73,727)	(50,754)	(32,115)	(24,717)
Other Expenses	(7,518)	(8,907)	(7,252)	(5,072)	(5,093)
Renewable Energy Credit	--	--	--	14,793	6,826
Equity (Loss) in Joint Power Agencies[4]	1,223	1,736	5,002	(3,575)	6,111
Net Income Before Operating Transfers and Extraordinary Items	$(46,270)	$ (4,343)	$ 26,294	$ 43,292	$ 13,354
Selected Balance Sheet Information (as of June 30)					
Rate Stabilization Fund	$ 25,000	$ 25,000	$109,244[5]	$109,688	$102,259
Cost Reduction Fund	98,739	84,207	N/A[5]	N/A[5]	N/A[5]
Cash Designated for Construction	64,017	54,857	57,487	61,617	45,846
Other Unrestricted Cash	72,684	65,282	67,028	87,462	82,463
Total Pooled & Cash Investments	$260,440	$229,346	$233,759	$258,767	$230,568

* Columns may not add to totals due to rounding.
(1) See “Rates and Charges” above. Exclude public benefit charge revenues.
(2) Includes purchased power payments and payments to joint power agencies. Also includes payment of a portion of gross revenues to City’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 City Charter, up to 5% of gross revenues (not including revenues from wholesale transactions) from the electric utility is paid to the City’s General Fund each year.
(3) Primarily represents interest income, public benefit charge revenues, grants, rents, and other non-recurring miscellaneous income. Unrealized gains were included in fiscal year 2008-09 ($9.558 million). Unrealized losses were included in fiscal years 2009-10 ($0.169 million), 2010-11 ($4.745 million) and 2011-12 ($0.784 million) and 2012-13 ($3.853 million). In 2010-11, 2011-12 and 2012-13, also net of gain (loss) on retirement of fixed assets.
(4) Net loss in fiscal year 2011-12 as a result of NCPA refunds to participants.
(5) As described herein, 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 electric revenue bonds are issued requires Santa Clara to produce revenues of the electric utility 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 electric revenue bonds and parity debt for such fiscal year. The electric revenue bond indenture permits amounts in the Rate Stabilization Fund or (prior to December 31, 2010) other unrestricted funds of the electric enterprise 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" above. The coverage numbers shown below differ in certain years from those previously reported, and they more accurately reflect the effects of wholesale transactions, the discharge of Santa Clara's senior lien electric revenue bond indenture in fiscal year 2007-08, the priority of payments under the Santa Clara City Charter and the terms of the electric revenue bond indenture.

CITY OF SANTA CLARA
RATE COVENANT COMPLIANCE UNDER
ELECTRIC REVENUE BOND INDENTURE
($ in 000s)

	Fiscal Year Ending June 30,				
	2009	**2010**	**2011**	**2012**	**2013**
Debt Service Coverage:					
Adjusted Revenues[(1)]	$297,506	$274,705	$274,261	$285,423	$291,696
Adjusted Operating Expenses[(2)]	276,574	239,773	238,590	238,074	266,246
Adjusted Net Revenue Available for Debt Service	$ 20,932	$ 34,932	$ 35,671	$ 47,349	$ 25,450
Debt Service on Electric Revenue Bonds[(3)]	$ 14,642	$ 12,293	$ 14,240	$ 16,888	$ 17,272
Adjusted Revenues in Excess of Debt Service Requirements	$ 6,289	$ 22,639	$ 21,431	$ 30,461	$ 8,178
Debt Service Coverage Ratio[(4)]	1.43	2.84	2.50	2.80	1.47

* Numbers may not add up due to independent rounding.

(1) Adjusted Revenue includes operating revenues and non-operating revenues (other income excluding unrealized gains or losses and developer contributions), and net of wholesale transactions, excluding equity or loss on joint powers agency projects accounted for on the equity method of accounting. Also includes Rate Stabilization Fund (formerly Cost Reduction Fund) transfers related to operating expenses. In fiscal years 2008-09, 2009-10 and 2012-13, such Coat Reduction Fund transfers were $40.544 million, $6.240 million, and $7.43 million, respectively. No Rate Stabilization Fund transfers were made in fiscal year 2010-11. In fiscal year 2011-12, the amount of $444,000 was transferred into the Rate Stabilization Fund. See "Rates and Charges" and "Cash Reserves" above.

(2) 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.

(3) Includes letter of credit fees relating to variable rate electric revenue bonds.

(4) Coverage of electric revenue bonds only. Excludes joint powers obligations, the costs of which are a component of Adjusted Operating Expenses. See footnote (2).

Source: City of Santa Clara.

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APPENDIX B

NCPA AUDITED FINANCIAL STATEMENTS FOR THE FISCAL YEARS ENDED JUNE 30, 2013 AND JUNE 30, 2012

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A PUBLIC AGENCY

NCPA

NORTHERN CALIFORNIA POWER AGENCY

AND ASSOCIATED POWER CORPORATIONS

Reports on Audit of Combined Financial Statements
and
Supplementary Information

For the Years Ended June 30, 2013 and 2012

NORTHERN CALIFORNIA POWER AGENCY
AND ASSOCIATED POWER CORPORATIONS

Reports on Audit of Combined Financial Statements
and Supplementary Information

Table of Contents

For the Years Ended June 30, 2013 and 2012

REPORT OF INDEPENDENT AUDITORS

The Board of Commissioners
Northern California Power Agency and Associated Power Corporations

Report on the Financial Statements
We have audited the accompanying combined financial statements of Northern California Power Agency and Associated Power Corporations (the Agency), which comprise the combined statement of net position as of June 30, 2013 and 2012, and the related combined statements of revenue, expenses and change in net position, and cash flows for the years then ended, and the related notes to the financial statements.

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

Auditor's Responsibility
Our responsibility is to express an opinion on these combined financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the combined financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the combined financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the combined financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the combined financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion
In our opinion, the combined financial statements referred to above present fairly, in all material respects, the combined financial position of Northern California Power Agency and Associated Power Corporations as of June 30, 2013 and 2012, and the combined results of their operations and their cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

REPORT OF INDEPENDENT AUDITORS (continued)

Opinion

In our opinion, the combined financial statements referred to above present fairly, in all material respects, the combined financial position of Northern California Power Agency and Associated Power Corporations as of June 30, 2013 and 2012, and the combined results of their operations and their cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Other Matters

Required Supplementary Information

Accounting principles generally accepted in the United States of America require that the management's discussion and analysis on pages 3 through 10 be presented to supplement the combined financial statements. Such information, although not a part of the combined financial statements, is required by the Governmental Accounting Standards Board who considers it to be an essential part of financial reporting for placing the basic financial statements in an appropriate operational, economic, or historical context. We have applied certain limited procedures to the required supplementary information in accordance with auditing standards generally accepted in the United States of America, which consisted of inquiries of management about the methods of preparing the information and comparing the information for consistency with management's responses to our inquiries, the combined financial statements, and other knowledge we obtained during our audit of the basic financial statements. We do not express an opinion or provide any assurance on the information because the limited procedures do not provide us with sufficient evidence to express an opinion or provide any assurance.

Other Information

Our audit was conducted for the purpose of forming an opinion on the financial statements that collectively comprise the Agency's combined financial statements. The combining statement of net position, combining statement of revenues, expenses and changes in net position and combining cash flows as of and for the year ended June 30, 2013 (combining financial statements) are presented for purposes of additional analysis and is not a required part of the combined financial statements.

The combining financial statements are the responsibility of management and are derived from and relates directly to the underlying accounting and other records used to prepare the combined financial statements. Such information has been subjected to the auditing procedures applied in the audit of the combined financial statements and certain additional procedures, including comparing and reconciling such information directly to the underlying accounting and other records used to prepare the combined financial statements or to the combined financial statements themselves, and other additional procedures in accordance with auditing standards generally accepted in the United States of America. In our opinion, the combining financial statements are fairly stated, in all material respects, in relation to the combined financial statements as a whole.

Moss Adams LLP

Portland, Oregon
October 30, 2013

MANAGEMENT'S DISCUSSION AND ANALYSIS

NORTHERN CALIFORNIA POWER AGENCY AND ASSOCIATED POWER CORPORATIONS

The following management's discussion and analysis of the Northern California Power Agency (the Agency) and its financial performance provides an overview of the Agency's financial activities for the years ended June 30, 2013 and 2012. This discussion should be read in conjunction with the Agency's combined financial statements and accompanying notes, which follow this section.

BACKGROUND

The Northern California Power Agency is a joint powers agency formed by member public entities under the laws of the State of California. The Agency is responsible for purchasing, generating, transmitting, and selling electrical energy and for providing other related services to its members as each may require. The Agency provides a portion of certain of its members' power needs and certain of its members also self-provide and or purchase power and transmission from other public and private sources.

The Agency is governed by a Commission comprised of one representative for each member. The Commission is responsible for the general management of the affairs, property, and business of the Agency. Under the direction of the General Manager, the staff of the Agency is responsible for providing various administrative, operating and planning services for the Agency.

The Agency's project construction and development programs have been individually financed by project revenue bonds that are collateralized by the Agency's assignment of all payments, revenues, and proceeds associated with its interest in each project. Each of the Agency's members may choose which projects in which it wishes to participate, as to each such project in which an Agency member participates, that member is known as a "project participant." Each project participant has agreed to pay its proportionate share of debt service and other costs of the related project, notwithstanding the suspension, interruption, interference, reduction or curtailment of output from the project for any reason (that is, the take-or-pay member agreements). Certain of the revenue bonds are additionally supported by municipal bond insurance credit enhancements.

Power sales by the Agency to its members for their resale include both sales of power to project participants generated by operating plants and power purchased from outside sources. Rates for power sales are designed to recover costs that include budgeted annual operating costs and debt service. Additional amounts for operating reserves or rate stabilization may be included in rates under the terms of bond indentures. The Agency's rates for electric service are not subject to the regulatory jurisdiction of the California Public Utilities Commission (CPUC) or the Federal Energy Regulatory Commission (FERC). Rather, the Agency's rates are established annually in connection with its budget, which is approved by its governing Commission.

Various legal and tax considerations caused the Agency to provide that separate not-for-profit corporations should be delegated by the Agency to own the geothermal electrical generating projects undertaken by the Agency ("the Associated Power Corporations"). The Associated Power Corporations, consisting of Northern California Municipal Power Corporation Nos. Two and Three, have delegated to the Agency the authority to construct, operate and manage their respective geothermal plants and related assets. The Agency, in return for financing the costs of acquisition and construction, acquires all the capacity and energy generated by the plants.

Because the Agency is a separate, governmental and not-for-profit organization that serves its participating members, who are also the Agency's principal customers, the net results of operations flow through to its participating members as either net revenues or net expenses.

MANAGEMENT'S DISCUSSION AND ANALYSIS

NORTHERN CALIFORNIA POWER AGENCY
AND ASSOCIATED POWER CORPORATIONS

FINANCIAL REPORTING

For accounting purposes, the Agency is a special-purpose governmental entity that is engaged in a business-type activity, principally as a supplier of wholesale electricity and transmission to its member participants. As such, the Agency's financial statements are presented as an enterprise type fund.

The records of the Agency and the Associated Power Corporations are maintained substantially in accordance with the FERC Uniform System of Accounts. Accounting principles generally accepted in the United States of America are applied by the Agency in conformance with pronouncements of the Governmental Accounting Standards Board (GASB). The combined financial statements encompass the Agency and Associated Power Corporations on an accrual accounting basis. All significant intercompany balances and transactions have been eliminated from the combined amounts reported.

In accordance with GASB Statement of Government Accounting Standards No. 62, Codification of Accounting and Financial Reporting for Proprietary Funds and Other Governmental Entities that use Proprietary Fund Accounting (GASB No. 62), the Agency has deferred certain items of expense and revenue that otherwise would have been charged to operations as such items will be recovered in the future years' operations. The Agency expects to recover these items in rates over the term of the related debt obligations it has issued.

COMBINED STATEMENT OF NET POSITION, COMBINED STATEMENTS OF REVENUES, EXPENSES AND CHANGES IN NET POSITION, AND COMBINED STATEMENTS OF CASH FLOW

The combined statement of net position include all the Agency's assets and liabilities, using the accrual method of accounting, as well as information about which assets can be used for general purposes and which assets are restricted as a result of bond covenants and other commitments. The combined statement of net position provides information about the nature and amount of resources and obligations at a specific point in time. The combined statements of revenues, expenses, and changes in net position report all the revenues and expenses during the time periods indicated. The combined statements of cash flow report the cash provided and used by operating activities as well as other cash sources, such as investment income and debt financing; and, other cash uses such as payments for debt service and capital additions.

NEW PROJECT

The Lodi Energy Center (LEC) is a 280 MW base load, combined cycle, natural gas-fired, combustion turbine generating station (one gas turbine and one steam turbine) located in Lodi, California. Environmental review was completed through the Application For Certification Process (AFC) at the California Energy Commission in May 2010 and construction began in August 2010. Commercial operation was declared on November 27, 2012. Pursuant to the Lodi Energy Center Power Sales Agreement, the Agency agreed to construct and operate the LEC and has sold all of the capacity and energy of the LEC to thirteen participants (including four non-members) in accordance with their respective generation entitlement shares (GES). Each participant has agreed to unconditionally provide for its share of the costs of construction of the LEC and all capital improvements and to pay its share of the operation and maintenance expenses based on its GES. The cost of the project was approximately $385.7 million for construction plus $38.4 million of capitalized interest.

MANAGEMENT'S DISCUSSION AND ANALYSIS

NORTHERN CALIFORNIA POWER AGENCY
AND ASSOCIATED POWER CORPORATIONS

FINANCIAL HIGHLIGHTS

The following is a summary of the Agency's combined financial position and results of operations for the years ended June 30, 2013, 2012, and 2011.

Condensed Statement of Net Position	June 30, (in thousands) 2013	2012	2011
Assets			
Current assets	$ 78,502	$ 68,042	$ 65,552
Restricted assets	213,807	221,700	312,148
Electric plant	676,070	684,399	584,928
Other assets	210,904	212,421	197,328
	$ 1,179,283	$ 1,186,562	$ 1,159,956
Liabilities and Net Position			
Long-term debt, net	$ 816,485	$ 843,692	$ 857,643
Current liabilities	92,118	80,481	78,070
Non-current liabilities	235,275	233,992	196,244
Net position:			
Net investment in capital assets	(55,630)	(51,007)	(49,429)
Restricted	64,737	52,873	50,652
Unrestricted	26,298	26,531	26.776
	$ 1,179,283	$ 1,186,562	$ 1,159,956

Condensed Statements of Revenues, Expenses and Changes in Net Position	Years Ended June 30, (in thousands) 2013	2012	2011
Sales for resale	$ 340,968	$ 277,257	$ 268,469
Operating expenses	(286,262)	(241,977)	(250,018)
Net operating revenues	54,706	35,280	18,451
Other expenses	(25,226)	(28,608)	(27,423)
Future recoverable (refundable) costs	(11,272)	6,514	15,426
Refunds to participants	(11,200)	(12,788)	(12,236)
Increase (decrease) in net position	7,008	398	(5,782)
Net position, beginning of year	28,397	27,999	33,781
Net position, end of year	$ 35,405	$ 28,397	$ 27,999

MANAGEMENT'S DISCUSSION AND ANALYSIS

NORTHERN CALIFORNIA POWER AGENCY
AND ASSOCIATED POWER CORPORATIONS

2013 Compared to 2012

ASSETS

Current Assets

Current assets increased $10.5 million or 15.4% from the prior year primarily due to cash provided by operating, investing and non-capital financing activities offset by a reduction in accounts receivable.

Restricted Assets

Restricted assets decreased $7.9 million or 3.6% from the prior year. This is primarily a result of Lodi Energy Center Project construction expenditures of $8.8 million and reduced Agency debt service of $4.1 million, which were offset by an increase in budgeted reserves of $5.0 million.

Electric Plant

The Agency has invested approximately $676.1 million in plant assets and construction work in progress, net of accumulated depreciation, at June 30, 2013. Net utility plant makes up approximately 57.3% of the Agency's assets. The $8.3 million or 1.2% decrease from the prior year consists of $30.7 million in depreciation, net of retirements of $3.7 million, offset by net capital expenditures of $18.7 million. For additional detail, refer to Note B.

Other Assets

Other assets decreased $1.5 million or 0.7% compared to 2012. This was primarily due to the write-off of preliminary survey and investigation costs, and certain bond cost amortizations.

LIABILITIES

Long-Term Debt, net

Long-term debt decreased $27.2 million or 3.2% in 2013 as a result of scheduled principal payments of $29.4 million and the net change in current portion of long-term debt of $13.7 million offset by the issuance of $12.9 million of Geothermal bonds and approximately $3.0 million in amortization of deferred losses on bond refunding and net discounts. For additional detail, refer to Note D.

Current Liabilities

Current liabilities increased by $11.6 million or 14.5% in 2013. This is primarily due to increases in current portion of long-term debt of $13.7 million and additional operating reserves for the LEC of $10.6 million along with reserve increases of $2.5 million, which are offset by decreases in accounts and retentions payable of $14.4 million related primarily to the Lodi Energy Center Project, and net decreases of approximately $0.8 million in accrued interest and advances.

Non-Current Liabilities

Non-current liabilities increased by a net of $1.3 million or 0.5% in 2013. This was primarily due to an $11.3 million increase of the regulatory liability, which is primarily related to the Lodi Energy Center Project, offset by net decreases of $7.4 million and $2.6 million in the interest rate swap liability and in operating reserves and other deposits, respectively.

NORTHERN CALIFORNIA POWER AGENCY
AND ASSOCIATED POWER CORPORATIONS

2013 Compared to 2012 - Continued

CHANGES IN NET POSITION

The Agency is intended to operate on a not-for-profit basis. Therefore, net position primarily represents differences between total revenues collected, using rates based on estimated operating expenses and debt service, and the total actual expenses incurred. In subsequent periods of operation, excess collections (net of encumbrances) may be refunded to participants or appropriated for other uses at the discretion of the Agency's governing Board of Commissioners. In the event the Agency incurs a net expense at year-end, the balance would be subject to recovery in participant rates under the terms of the related participating member agreements. See Notes A, B and D to the Combined Financial Statements.

Sales For Resale
Sales for resale revenues for fiscal year 2013 were approximately $63.7 million or 23.0% higher than in the prior fiscal year. This was the net result of the following: (1) higher sales for resale revenues from Agency participants of $41.2 million or 16.5%, which was caused by increased budget requirements of plant operations of $38.2 million primarily due to the LEC, which began operations in November 2012, along with increased transmission requirements of $11.9 million, which were offset by reduced power purchase requirements of $8.9 million due to the additional generation of the LEC project; and (2) increased other third party revenues of $22.5 million or 81.0%, which was primarily the result of increased energy sales into the ISO market from the Lodi Energy Center project.

Operating Expenses
Operating expenses increased by approximately $44.3 million or 18.3% in fiscal year 2013, as compared with the prior year. This was the net result of the following: (1) operations expenses increased $26.8 million or 75.6% due to costs of the LEC which began operation on November 27, 2012; (2) the maintenance cost component increased by $11.5 million or 107.8%, of which $6.7 million was due to the LEC, including long-term maintenance agreement costs; and, $4.8 million of increased geothermal turbine generator maintenance projects; and (3) net increases in depreciation, administrative and general and transmission, offset by decreased purchased power expenses totaling approximately $6.0 million.

2012 Compared to 2011

ASSETS

Restricted Assets
Restricted assets decreased $90.4 million or 29.0% from the prior year. This is primarily a result of Lodi Energy Center Project expenditures related to construction of $99.3 million and debt service of $17.5 million, which were offset by (1) an increase of General Operating Reserve participant deposits of $7.8 million; (2) increases in the Capital Facilities Project debt service account of $2.3 million, Hydroelectric Project debt service and other reserve accounts of $5.8 million and $4.7 million, respectively, due to the effects of increased debt service requirements and the 2012A refunding; (3) an increase in budgeted reserves of $5.7 million; and (4) a decrease in interest receivable of $0.1 million due to the declining LEC construction and debt service balances.

**NORTHERN CALIFORNIA POWER AGENCY
AND ASSOCIATED POWER CORPORATIONS**

2012 Compared to 2011 - Continued

Electric Plant

The Agency has invested approximately $684.4 million in plant assets and construction work in progress, net of accumulated depreciation, at June 30, 2012. Net utility plant makes up approximately 57.7% of the Agency's assets. The $99.5 million increase from the prior year is a result of an increase in construction work in progress of $122.6 million primarily related to the Lodi Energy Center Project, offset by $24.0 million in depreciation, net of retirements of $0.9 million. For additional detail, refer to Note B.

Other Assets

Other assets increased $15.1 million compared to 2011. This was primarily due to reduced bond principal collections compared to scheduled asset depreciation and bond cost amortizations.

LIABILITIES

Long-Term Debt, net

Long-term debt decreased $14.0 million in 2012 as a result of scheduled principal payments of $11.2 million and the net change in current portion of long-term debt of $9.5 million offset by the effects of $3.7 million related to the refunding of certain Hydroelectric bonds and approximately $3.0 million in amortization of deferred losses on bond refunding and net discounts. For additional detail, refer to Note D.

Current Liabilities

Current liabilities increased by $2.4 million in 2012. This is primarily due to an increase in current portion of long-term debt of $9.5 million, which was offset by decreases in accounts and retentions payable-restricted of $6.0 million related primarily to the Lodi Energy Center Project, and net decreases of approximately $1.1 million in accrued interest, reserves and advances.

Non-Current Liabilities

Non-current liabilities increased by approximately $37.7 million in 2012. This was primarily due to (1) a $16.8 million increase in operating reserves and other deposits, including increases of $7.8 million in the General Operating Reserve, an increase in budgeted reserves of $4.9 million, and additional deposits of $4.1 million to meet Balancing Account and project O&M reserve requirements; (2) an $11.3 million increase of deferred revenues primarily related to the Lodi Energy Center Project; and (3) a net increase of $9.6 million in the interest rate swap liability.

CHANGES IN NET POSITION

The Agency is intended to operate on a not-for-profit basis. Therefore, net position primarily represent differences between total revenues collected, using rates based on estimated operating expenses and debt service, and the total actual expenses incurred. In subsequent periods of operation, excess collections (net of encumbrances) may be refunded to participants or appropriated for other uses at the discretion of the Agency's governing Board of Commissioners. In the event the Agency incurs a net expense at year-end, the balance would be subject to recovery in participant rates under the terms of the related participating member agreements. See Notes A, B and D to the Combined Financial Statements.

2012 Compared to 2011 - Continued

Sales For Resale

Sales for resale revenues for fiscal year 2012 were approximately $8.8 million or 3.3% higher than in the prior fiscal year. This was the net result of the following: (1) higher sales for resale revenues from Agency participants of $6.0 million or 2.5%, which was caused primarily by increased budget requirements for steam drilling and scheduled debt service, which was offset by reduced power purchase requirements due to a decline in participant demand with a lower average cost of power and a reduction of budgeted management services requirements compared to 2011; and (2) higher other third-party revenues of $2.8 million or 11.3%, which was the result of increased drill rig rental activity of $3.1 million and additional solar rebates of $1.7 million. This additional revenue was offset by $2.0 million of lower market power sales, ancillary services and other revenues.

Operating Expenses

Operating expenses decreased by approximately $8.0 million or 3.2% in fiscal year 2012, as compared with the prior year. This was the net result of the following: (1) the cost of the purchased power component decreased by $7.3 million or 6.4%, largely due to the reduced need for power previously noted above; (2) the operations cost component increased by $3.5 million or 11.1% primarily due to increased steam field drilling expenses of $5.2 million offset by a net decrease in other projects of $1.7 million; and (3) decreases in maintenance expense, depreciation and administrative expenses totaling approximately $4.4 million.

FINANCING ACTIVITIES

During 2013 and 2012 the Agency continued to implement strategies to further improve its competitive position and financial flexibility. These actions included (1) financing of certain plant improvements to increase generation; (2) the refunding of fixed rate debt for debt service savings; and (3) replacing the letter of credit provider related to outstanding variable rate bonds.

In September 2012, the Agency issued $12,910,000 of fixed rate tax exempt bonds for the purpose of providing funds to finance the costs of acquisition and construction of certain improvements to the project as well as make a contribution to the Debt Service Reserve Account and to pay the costs of issuance of the 2012 Series A Bonds. Capital improvements financed include Plant 1 turbine upgrades for both Units 1 and 2 and modifications to the main steam line to reduce pressure losses and increase MW production. The bonds are of varying principal amounts ranging from $475,000 to $725,000 through July 1, 2022 and bear interest at 2.289%.

In February 2012, the Agency refunded $88,355,000 principal amount of 1998 Hydroelectric Refunding Revenue Bonds Series A maturing on July 1 in each of the years 2024 through 2032. The refunding was completed through the issuance of $76,665,000 fixed rate tax exempt debt (2012 Series A) and $7,120,000 fixed rate taxable debt (2012 Series B) with yields of 3.05% to 4.32% with varying principal maturities ranging from $4,475,000 to $13,040,000 through July 1, 2032. The refunding is estimated to have decreased project debt service by an estimated $14.4 million over the next 21 years, which results in an estimated economic gain to the Agency of approximately $9.4 million.

NORTHERN CALIFORNIA POWER AGENCY AND ASSOCIATED POWER CORPORATIONS

The Agency has issued variable rate 2008 Hydroelectric Refunding Series A ($85,160,000) bonds and 2008 Hydroelectric Refunding Series B ($3,165,000) bonds. To support this financing, the Agency entered into two irrevocable direct pay letter of credit agreements with Dexia Credit Local, which were to expire on April 2, 2013. Due to certain impacts on Dexia's credit rating and the resulting negative potential effect on the Agency's variable interest rate, on September 27, 2011, the irrevocable direct pay letter of credit agreements with Dexia Credit Local related to the 2008 Hydroelectric Refunding Series A and B bonds were terminated. Replacement letters of credit with Citibank N.A. were issued on the same day. The Citibank letters of credit are for a period of three years and expire on September 27, 2014.

Ratings assigned to the Agency's outstanding project bonds as of June 30, 2013 are as follows:

Debt Credit Ratings:	Standard & Poor's	Fitch	Moody's
Geothermal	A-, stable	A+, stable	A1, stable
Hydroelectric	A+, stable	A+, stable	A2, stable
Capital Facilities	A-, stable	Not rated	A3, stable
Lodi Energy Center (Issue One)	A-, stable	A, stable	A3, stable
Lodi Energy Center (Issue Two)	AAA, stable	Not rated	Aa2, stable

SUMMARY

The management of the Agency is responsible for preparing the information in this management's discussion and analysis, combined financial statements and notes to combined financial statements. Financial statements were prepared according to accounting principles generally accepted in the United States of America, and they fairly portray the Agency's financial position and results of operations. The notes to the financial statements are an integral part of the basic financial statements and provide additional financial information.

Agency Financials

COMBINED STATEMENT OF NET POSITION

**NORTHERN CALIFORNIA POWER AGENCY
AND ASSOCIATED POWER CORPORATIONS**

	June 30, 2013	June 30, 2012
ASSETS	(in thousands)	
CURRENT ASSETS		
Cash and cash equivalents	$ 59,511	$ 56,553
Investments	7,452	-
Accounts receivable		
Participants	207	3,373
Other	3,103	1,215
Interest receivable	38	12
Inventory and supplies – at average cost	7,118	5,923
Prepaid expenses	1,073	966
TOTAL CURRENT ASSETS	78,502	68,042
RESTRICTED ASSETS		
Cash and cash equivalents	59,111	68,932
Investments	154,550	152,575
Interest receivable	146	193
TOTAL RESTRICTED ASSETS	213,807	221,700
ELECTRIC PLANT		
Electric plant in service	1,494,747	1,072,275
Less: accumulated depreciation	(831,144)	(804,203)
	663,603	268,072
Construction work-in-progress	12,467	416,327
TOTAL ELECTRIC PLANT	676,070	684,399
OTHER ASSETS		
Regulatory assets	199,749	200,000
Unamortized debt issuance expenses	10,876	11,168
Preliminary survey and investigation costs	279	1,253
TOTAL OTHER ASSETS	210,904	212,421
TOTAL ASSETS	$ 1,179,283	$ 1,186,562

See notes to combined financial statements

COMBINED STATEMENT OF NET POSITION

NORTHERN CALIFORNIA POWER AGENCY
AND ASSOCIATED POWER CORPORATIONS

	June 30, 2013	June 30, 2012
LIABILITIES	(in thousands)	
CURRENT LIABILITIES		
Accounts payable	$ 25,916	$ 21,715
Accounts and retentions payable – restricted for construction	696	19,293
Member advances	1,158	2,158
Operating reserves	16,259	3,111
Current portion of long-term debt	34,365	20,635
Accrued interest payable	13,724	13,569
TOTAL CURRENT LIABILITIES	92,118	80,481
NON-CURRENT LIABILITIES		
Operating reserves and other deposits	124,515	127,163
Regulatory liability	95,768	84,487
Interest rate swap liability	14,992	22,342
Long-term debt, net	816,485	843,692
TOTAL NON-CURRENT LIABILITIES	1,051,760	1,077,684
TOTAL LIABILITIES	1,143,878	1,158,165
NET POSITION		
Net investment in capital assets	(55,630)	(51,007)
Restricted	64,737	52,873
Unrestricted	26,298	26,531
TOTAL NET POSITION	35,405	28,397
TOTAL LIABILITIES AND NET POSITION	$ 1,179,283	$ 1,186,562

COMBINED STATEMENTS OF REVENUES, EXPENSES AND CHANGES IN NET POSITION

NORTHERN CALIFORNIA POWER AGENCY AND ASSOCIATED POWER CORPORATIONS

	Years Ended June 30, 2013	2012
	(in thousands)	
SALES FOR RESALE		
Participants	$ 290,623	$ 249,439
Other Third-Party	50,345	27,818
TOTAL SALES FOR RESALE	340,968	277,257
OPERATING EXPENSES		
Purchased power	101,517	107,158
Transmission	52,389	49,440
Operations	62,168	35,396
Depreciation	30,680	24,008
Administrative and general	17,308	15,296
Maintenance	22,200	10,679
TOTAL OPERATING EXPENSES	286,262	241,977
NET OPERATING REVENUES	54,706	35,280
OTHER (EXPENSES) REVENUES		
Interest expense	(37,772)	(45,966)
Interest income	792	1,229
Capitalized interest	6,320	15,984
Amortization	(465)	(410)
Other	5,899	555
TOTAL OTHER EXPENSES	(25,226)	(28,608)
FUTURE RECOVERABLE AMOUNTS	(11,272)	6,514
REFUNDS TO PARTICIPANTS	(11,200)	(12,788)
INCREASE IN NET POSITION	7,008	398
NET POSITION, Beginning of year	28,397	27,999
NET POSITION, End of year	$ 35,405	$ 28,397

See notes to combined financial statements

COMBINED STATEMENTS OF CASH FLOW

NORTHERN CALIFORNIA POWER AGENCY AND ASSOCIATED POWER CORPORATIONS

	Years Ended June 30, 2013	2012
	(in thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Received from participants	$ 303,358	$ 257,464
Received from others	48,918	31,727
Payments for employee services	(30,701)	(30,592)
Payments to suppliers for goods and services	(229,565)	(180,746)
NET CASH FROM OPERATING ACTIVITIES	92,010	77,853
CASH FLOWS FROM INVESTING ACTIVITIES		
Proceeds from maturities and sales of investments	251,609	210,240
Interest received on cash and investments	989	1,799
Purchase of investments	(270,779)	(212,919)
NET CASH FROM INVESTING ACTIVITIES	(18,181)	(880)
CASH FLOWS FROM CAPITAL AND RELATED FINANCING ACTIVITIES		
Expenditures for debt issuance costs	(173)	(2,431)
Acquisition and construction of electric plant	(16,828)	(107,495)
Interest paid on long-term debt	(42,067)	(44,175)
Principal repayment on long-term debt	(29,234)	(11,175)
Proceeds from bond issues	12,910	94,108
Payments to refund debt	-	(87,059)
NET CASH FROM CAPITAL AND RELATED FINANCING ACTIVITIES	(75,392)	(158,227)
CASH FLOWS FROM NON-CAPITAL AND RELATED FINANCING ACTIVITIES		
Advances from members	-	204
Other proceeds	5,900	556
Preliminary survey and investigation costs	-	(103)
Refunds to participants	(11,200)	(12,788)
NET CASH FROM NON-CAPITAL AND RELATED FINANCING ACTIVITIES	(5,300)	(12,131)
DECREASE IN CASH AND CASH EQUIVALENTS	(6,863)	(93,385)
CASH AND CASH EQUIVALENTS		
Beginning of year	125,485	218,870
End of year	$ 118,622	$ 125,485

See notes to combined financial statements

NORTHERN CALIFORNIA POWER AGENCY
AND ASSOCIATED POWER CORPORATIONS

	Years Ended June 30,	
	2013	2012
	(in thousands)	
RECONCILIATION OF NET OPERATING REVENUES TO NET CASH FROM OPERATING ACTIVITIES		
Net operating revenues	$ 54,706	$ 35,280
Adjustments to reconcile net operating revenues to net cash from operating activities:		
Depreciation	30,680	24,008
	85,386	59,288
CASH FLOWS IMPACTED BY CHANGES IN		
Accounts receivable	1,278	(3,412)
Inventory and prepaid expense	(1,302)	(60)
Preliminary survey and investigation costs	(26)	-
Operating reserves and other deposits	10,500	16,740
Regulatory assets	(1,451)	-
Regulatory liabilities	12,021	11,346
Accounts payable	(14,396)	(6,049)
NET CASH FROM OPERATING ACTIVITIES	$ 92,010	$ 77,853
CASH AND CASH EQUIVALENTS AS STATED IN THE COMBINED STATEMENT OF NET POSITION		
Cash and cash equivalents - current assets	$ 59,511	$ 56,553
Cash and cash equivalents - restricted assets	59,111	68,932
End of year	$ 118,622	$ 125,485

NORTHERN CALIFORNIA POWER AGENCY
AND ASSOCIATED POWER CORPORATIONS
June 30, 2013 and 2012

NOTE A -- ORGANIZATION

The Agency Northern California Power Agency (Agency) was formed in 1968 as a joint powers agency of the State of California. The membership consists of eleven cities with publicly-owned electric utility distribution systems, one port authority, a transit authority, and two other associate member entities. The Agency is generally empowered to purchase, generate, transmit, distribute, and sell electrical energy. Members participate in the projects of the Agency on an elective basis.

Various legal and tax considerations caused the Agency to provide that separate not-for-profit corporations should be delegated by the Agency to own the geothermal electrical generating projects undertaken by the Agency ("the Associated Power Corporations"). The Associated Power Corporations, Northern California Municipal Power Corporations Nos. Two and Three, have delegated to the Agency the authority to construct, operate and manage their respective geothermal plants and related assets. The Agency, in return for financing the costs of acquisition and construction, acquires all the capacity and energy generated by the plants. See Note D – Projects and Related Financing.

The Agency is governed by a Commission comprised of one representative for each member. The Commission is responsible for the general management of the affairs, property, and business of the Agency. Under the direction of the General Manager, the staff of the Agency is responsible for providing various administrative, operating and planning services for the Agency.

NOTE B -- SIGNIFICANT ACCOUNTING POLICIES

Basis of Accounting and Principles of Combination For accounting purposes, the Agency is a special-purpose governmental entity that is engaged in a business-type activity, principally as a supplier of wholesale electricity and transmission to its member participants. As such, the Agency's financial statements are presented as an enterprise type fund.

The records of the Agency and its Associated Power Corporations are maintained substantially in accordance with the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts. Accounting principles generally accepted in the United States of America are applied by the Agency in conformance with pronouncements of the Governmental Accounting Standards Board (GASB). The combined financial statements encompass the Agency and Associated Power Corporations on an accrual accounting basis. All significant intercompany balances and transactions have been eliminated from the combined amounts reported.

Cash Operating cash is maintained in interest-bearing depository accounts, which are fully collateralized, in accordance with state law. Cash balances are invested in either overnight repurchase agreements, which are fully collateralized by U.S. Government Securities, or in money market funds invested in short-term U.S. Treasury Securities. The Agency commingles operating cash for investment purposes only. Separate detailed accounting records are maintained for each account's related investments. All cash of the Agency is held by either the Agency's custodian or its primary bank and revenue bond trustee.

Cash Equivalents Cash equivalents are short-term investments purchased with original maturities of 90 days or less. Cash equivalents consist primarily of portions of guaranteed investment contracts, U.S. Treasury and Agency Securities, California State Treasurer's pooled Local Agency Investment Fund (LAIF), and money market mutual funds.

Restricted Cash and Investments Long-term debt and other agreements require the maintenance of certain restricted asset accounts. Cash and investments held in these accounts are restricted for specific uses, including project construction, operations, debt service, and special reserve requirements. Investments are stated at cost adjusted for amortization of premiums and accretion of discounts, which approximates market.

Inventory and Supplies Inventory and supplies consist primarily of spare parts for the maintenance of plant assets and are stated at average cost.

Restricted Assets Cash and cash equivalents, investments and related accrued interest which are restricted under terms of certain agreements, trust indentures or Commission actions limiting the use of such funds, are included in restricted assets.

Electric Plant Electric plant in service is recorded at historical cost. The cost of additions, renewals and betterments is capitalized; repairs and minor replacements are charged to operating expenses as incurred. The original cost of property retired, net of removal and salvage costs, is charged to accumulated depreciation. Depreciation expense is computed using the straight-line method over the estimated useful lives of the related assets. The provision for depreciation was approximately 2.4% and 2.2% of the average electric plant in service for the Agency during 2013 and 2012, respectively. Depreciation is calculated using the following estimated lives:

Generation and Transmission	25 to 42 years
General Plant	5 to 25 years
Transportation Equipment	5 years

A summary of changes in electric plant for the year ended June 30, 2013 is as follows:

	Balance June 30, 2012	Additions	Deletions	Balance June 30, 2013
		(in thousands)		
Structures and Leasehold Improvements	$ 293,012	$ 26,916	$ -	$ 319,928
Reservoirs, Dams and Waterways	249,318	21	-	249,339
Equipment	354,522	399,258	(3,736)	750,044
Furniture and Fixtures	3,478	18	(5)	3,491
	900,330	426,213	(3,741)	1,322,802
Accumulated Depreciation	(804,203)	(30,680)	3,739	(831,144)
	96,127	395,533	(2)	491,658
Construction Work-In-Progress	416,327	20,635	(424,495)	12,467
Land and Land Rights	171,945	-	-	171,945
Electric Plant, Net	$ 684,399	$ 416,168	$ (424,497)	$ 676,070

A summary of changes in electric plant for the year ended June 30, 2012 is as follows:

	Balance June 30, 2011	Additions	Deletions	Balance June 30, 2012
	(in thousands)			
Structures and Leasehold Improvements	$ 292,944	$ 68	$ -	$ 293,012
Reservoirs, Dams and Waterways	249,449	79	(210)	249,318
Equipment	355,205	931	(1,614)	354,522
Furniture and Fixtures	3,478	-	-	3,478
	901,076	1,078	(1,824)	900,330
Accumulated Depreciation	(781,848)	(24,008)	1,653	(804,203)
	119,228	(22,930)	(171)	96,127
Construction Work-In-Progress	293,755	123,310	(738)	416,327
Land and Land Rights	171,945	-	-	171,945
Electric Plant, Net	$ 584,928	$ 100,380	$ (909)	$ 684,399

Construction Work-In-Progress Construction work-in-progress (CWIP) includes the capitalized cost of land, material, equipment, labor, interest (net of interest income), certain other financing costs incurred to facilitate the projects and an allocated portion of general and administrative expenses related to the development of electric plant. In addition, CWIP ultimately includes costs incurred during the test and start-up phase of projects prior to commencement of commercial operations.

Preliminary Surveys and Investigations Expenditures for preliminary surveys, plans and investigations (PS&I) are deferred until the ultimate feasibility of the contemplated project is determined. When a project is continued, these expenditures are capitalized as part of construction work-in-progress and the related advances provided by members to fund such expenditures are repaid out of the permanent financing of the project. If a project is abandoned, such expenditures and related advances are included in operations when such determination is made.

Regulatory Assets/Liabilities In accordance with GASB No. 62, the Agency has deferred certain items of expense and revenue that otherwise would have been charged to operations because it is probable that such items will be recovered in the future years' operations. The Agency expects to recover these items in rates over the term of the related debt obligations it has issued. On an ongoing basis, the Agency reviews its operations to determine the continued applicability of these deferrals under GASB No. 62.

The items of expense that have been deferred are those originally paid from bond proceeds, including depreciation, certain bond amortizations and interest paid from bond proceeds. Revenues used to acquire electric plant have also been deferred to future years. As of June 30, 2013 and 2012, the Agency had accumulated regulatory assets (net of regulatory liabilities) of approximately $103,981,000 and $115,513,000, respectively.

Unamortized Debt Issuance Expenses Debt issuance expenses are amortized over the term of the related issue. Amortization is computed using the effective interest method.

Compensated Absences Accumulated unpaid compensated absences are accrued as the obligation is incurred. Compensated absences are included in current liabilities.

Long-Term Debt Long-term debt is stated net of unamortized discounts and premiums and excess cost on advanced refunding of debt. Discounts and premiums are amortized over the term of the related obligation using the effective interest method. Amortization of debt discounts and premiums is included in total interest expense for the period. See Note D - Projects and Related Financing.

Operating Reserves The Agency has established various funded operating reserves, in accordance with various bond indentures, project agreements and prudent utility practice, for anticipated periodic operating costs and related liabilities including, but not limited to, scheduled maintenance other than ordinary repairs and replacements. Certain amounts funded each year are charged to operating expense because the rates established by the Agency for power sales to its members include these costs on a prospective basis. Changes to operating reserve levels are periodically evaluated during the annual budgeting process. A non-project specific, individual participant controlled, general operating reserve is also maintained for participating Agency members.

Rates Power sales to participants for their resale include both power generated by operating plants and power purchased from outside sources. Rates for power sales are designed to recover costs that include budgeted annual operating costs and debt service. Additional amounts for operating reserves or rate stabilization may be included in rates under the terms of bond indentures. During fiscal years 2013 and 2012, no amounts were specifically collected for rate stabilization.

The Agency's rates for electric service are not subject to the regulatory jurisdiction of the California Public Utilities Commission (CPUC) or FERC. Rather, the Agency's rates are established annually in connection with its budget, which is approved by its governing Commission.

Power, Transmission and Fuel Forward Transactions In the normal course of its business, the Agency is required to manage loads, resources, and energy price risk on behalf of its members. Consequently, the Agency buys and sells power, transmission, and fuel in wholesale markets as required. The Agency does not enter into such agreements solely for trading purposes. All such transactions are normal purchases and sales subject to settlement at the agreed to contract prices for quantities delivered. While authorized to transact forward purchase contracts for terms of up to five years, forward contract purchases at fiscal year ended June 30, 2013 were for periods not greater than four and one half years duration beyond the current fiscal year. In the event of default, undelivered transactions are required to be marked-to-market subject to the following limitations. If the Agency, as buyer, is the defaulting entity, the Agency's termination settlement amount is capped at the agreed to contract cost for all future undelivered commodities. If the selling counterparty is the defaulting entity, the seller's termination settlement is not capped for all future undelivered commodities. The defaulting entity is also subject to resultant transmission charges, brokerage fees, attorney fees, and all other reasonable expenses. See Note G - Commitments and Contingencies, Power Purchase Contracts.

Fair Values of Financial Instruments The following methods and assumptions were used by the Agency in estimating its fair value disclosures for financial instruments:

Cash and Cash Equivalents - The carrying amount reported in the balance sheets for cash and cash equivalents approximates its fair value.

Investments - The fair values for investments are based on quoted market prices. See Note C.

Swaps - The fair values take into consideration the prevailing interest rate environment, the specific terms and conditions of a given transaction and any upfront payments that were received. All fair values were estimated using the zero-coupon discounting method. This method calculates the future payments required by the swap, assuming that the current forward rates implied by the yield curve are the market's best estimate of future spot interest rates. These payments are then discounted using the spot rates implied by the current yield curve for a hypothetical zero-coupon rate bond due on the date of each future net settlement on the swaps. While the current net mark to market values are negative, this valuation would be realized only if the swaps were terminated at the valuation date.

Net Position The Agency classifies its net position into three components; invested in capital assets, restricted and unrestricted. These classifications are defined as follows:

Invested in Capital Assets - This component consists of capital assets, net of accumulated depreciation reduced by outstanding debt balances, net of unamortized debt expenses and unspent bond proceeds.

Restricted - This component consists of net position with constraints placed on their use. Constraints include those imposed by debt indentures and other agreements; grants, laws and regulations of other governments; or, by the Agency's governing Board of Commissioners.

Unrestricted - This component consists of net position that does not meet the definition of "invested in capital assets" or "restricted".

The Agency and the Associated Power Corporations are intended to operate on a not-for-profit basis. Therefore, any balance of net position represents differences between total revenues collected, using rates based on estimated operating expenses and debt service, and the total actual expenses incurred. In subsequent periods of operation, excess collections (net of encumbrances) that the participating members do not direct be held by or released to the Agency are refunded to the participating members. Estimated encumbrances at June 30, 2013 and 2012 were $6,068,000 and $6,116,000, respectively. In the event the Agency incurs a negative net position balance, the balance would be subject to recovery in rates under the terms of the related take-or-pay member agreements. See Note D.

Recent Accounting Pronouncements In June 2011, GASB issued Statement of Governments Accounting Standards (SGAS) No. 63, "Financial Reporting of Deferred Outflows of Resources, Deferred Inflows of Resources and Net Position" (GASB63). GASB No. 63 amends the net asset reporting requirements in GASB No. 34, "Basic Financial Statements - and Management's Discussion and Analysis - for State and Local Governments" and other pronouncements by incorporating deferred outflow of resources and deferred inflow of resources into the definitions of the required components of the residual measure and by renaming that measure as net position, rather than net assets. This statement is effective for the Agency in the current fiscal year. Changes were limited to naming changes only. This statement had no material impact on the financial statements of the Agency.

In March 2012, GASB issued SGAS No. 65, "Items Previously Reported as Assets and Liabilities" (GASB65). GASB No. 65 establishes accounting and financial reporting standards that either (a) properly classifies certain items that were previously reported as assets and liabilities as deferred outflows of resources or deferred inflows of resources or (b) recognize certain items that were previously reported as assets and liabilities as outflows of resources (expenses/expenditures) or inflows of resources (revenues). The statement also limits the term "deferred" to items reported as deferred outflows of resources or deferred inflows of resources. This statement is effective for the Agency in FY 2014. The Agency is currently assessing the financial statement impact of adopting the statement, but does not believe that its impact will be material.

Use of Estimates in the Preparation of Financial Statements The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amount of revenues and expenses during the reporting period. Actual results could differ from those estimates.

NOTE C -- INVESTMENTS

The Agency is authorized to invest in obligations of the U.S. Government and its agencies and instrumentalities, in certificates of deposit, commercial paper, banker's acceptances, repurchase agreements, passbook savings account demand deposits, municipal bonds, the State Treasurer's LAIF pool, and in other instruments authorized by applicable sections of the Government Code of the State of California. The Agency's investments are stated at cost adjusted for amortization of premiums and accretion of discounts, which approximates market.

Investments at June 30, 2013

Description	Carrying Value	Market Value	Wtd. Avg Maturity (In years)
	(in thousands)		
U.S. Agencies	$ 162,002	$ 161,139	1.96
TOTAL INVESTMENTS	$ 162,002	$ 161,139	

Investments at June 30, 2012

Description	Carrying Value	Market Value	Wtd. Avg Maturity (In years)
	(in thousands)		
U.S. Agencies	$ 152,575	$ 152,780	1.01
TOTAL INVESTMENTS	$ 152,575	$ 152,780	

The Agency's investment policy requires investments that assure safety of the principal, liquidity to meet specific obligations of the Agency when due, and investment quality all in compliance with California State law and the Agency's revenue bond indentures. Generally, operating investment maturities are limited to one year and reserve funds to five year maturities, except for debt service reserve funds, which are allowed maturities up to fifteen years. All U.S. Government and U.S. Government Agency securities held by the Agency are either in effect or actually AA rated.

NORTHERN CALIFORNIA POWER AGENCY AND ASSOCIATED POWER CORPORATIONS

All securities owned by or held on behalf of the Agency are held by either the Agency's custodian, Union Bank of California, N.A., or its revenue bond trustee, U.S. Bank Trust, N.A.

The Agency's investment policy includes restrictions for investments relating to maximum amounts invested as a percentage of the portfolio and with a single issuer, maximum maturities and minimum credit ratings.

Credit Risk To mitigate the risk that an issuer will not fulfill its obligation to the investment, the Agency limits investments to those rated, at a minimum, A or equivalent for long/medium term notes by a nationally recognized statistical rating organization.

Custodial Credit Risk This is the risk that in the event of a failure of a depository financial institution, the Agency's deposits may not be returned or the Agency will not be able to recover its deposits, investments or collateral securities that are in the possession of another party.

Concentration of Credit Risk This is the risk of loss attributed to the magnitude of an entity's investment in a single issuer. The Agency places no limit on the amounts invested in obligations of the U.S. Government and its agencies.

Interest Rate Risk Interest rate risk is the risk that changes in market interest rates may adversely affect the fair value of an investment. The Agency manages its exposure to interest rate risk by following a hold-to-maturity investment approach, purchasing a combination of shorter and longer term investments, and by timing cash flows from maturities so that a portion of the portfolio is maturing or coming close to maturity evenly over time as necessary to provide the cash flow and liquidity needed for operations.

NORTHERN CALIFORNIA POWER AGENCY
AND ASSOCIATED POWER CORPORATIONS

NOTE D -- PROJECTS AND RELATED FINANCING

Financing Programs The Agency's project construction and development programs have been individually financed by project revenue bonds that are collateralized by the Agency's assignment of all payments, revenues, and proceeds associated with its interest in each project. Each project participant has agreed to pay its proportionate share of debt service and other costs of the related project, notwithstanding the suspension, interruption, interference, reduction or curtailment of output from the project for any reason (that is, the take-or-pay member agreements).

Certain of the revenue bonds are additionally supported by municipal bond insurance credit enhancements.

Long-term debt and stated rates at June 30:	2013	2012
	(in thousands)	
Geothermal Project		
2009 Series A		
Serial, 4.00-5.50% through 2025	$ 31,895	$ 33,790
2012 Series A		
Term, 2.289% due 2023	12,435	-
Total Geothermal Project	44,330	33,790
Hydroelectric Project		
1992 Refunding Series A		
Term, 6.30% due 2019	36,770	36,770
2008 Refunding Series A		
Term, adjustable rate-weekly reset, due 2033	85,160	85,160
2008 Refunding Series B (Taxable)		
Term, adjustable rate-weekly reset, due 2021	2,610	2,845
2008 Refunding Series C		
Serial, 4.00-5.00% through 2025	109,250	118,345
2010 Refunding Series A		
Serial, 4.00-5.00% through 2024	101,260	101,260
2010 Refunding Series B		
Serial, 2.75-3.25% through 2014	1,755	8,025
2012 Refunding Series A		
Serial, 5.00% through 2033	76,665	76,665
2012 Refunding Series B		
Serial, 4.32% through 2025	7,120	7,120
Total Hydroelectric Project	420,590	436,190

Long-term debt and stated rates at June 30:	2013	2012
	(in thousands)	
Capital Facilities Project		
2010 Refunding Series A		
Serial, 2.00-5.25% through 2026	51,380	54,520
Total Capital Facilities Project	51,380	54,520
Lodi Energy Center, Issue One		
2010 Series A		
Serial, 3.00-5.00% through 2020	37,770	42,310
Term, 5.00% due 2025	36,020	36,020
2010 Series B (Federally Taxable – Direct Payment Build America Bonds)		
Term, 7.311% due 2040	176,625	176,625
Lodi Energy Center, Issue Two		
2010 Series A		
Serial, 3.00-5.00% through 2019	26,765	30,540
2010 Series B (Federally Taxable – Direct Payment Build America Bonds)		
Term, 4.63% due 2020	5,210	5,210
Term, 5.679% due 2035	105,015	105,015
Total Lodi Energy Center	387,405	395,720
Total Long-Term Debt Outstanding	903,705	920,220
Less: Unamortized net cost on advance refunding	(76,773)	(83,688)
Unamortized premium (discount), net	23,918	27,795
Current portion	(34,365)	(20,635)
Total Long-Term Debt, Net	$ 816,485	$ 843,692

The Agency had the following long-term debt activity during FY 2013:

	Balance June 30, 2012	Additions	Payments, Refundings & Amortizations	Balance June 30, 2013
		(in thousands)		
Revenue Bonds	$ 920,220	$ 12,910	$ (29,425)	$ 903,705
Unamortized premiums and discounts	27,795	-	(3,877)	23,918
Unamortized cost on advance refund of debt	(83,688)	-	6,915	(76,773)
TOTAL	$ 864,327	$ 12,910	$ (26,387)	$ 850,850

The Agency had the following long-term debt activity during FY 2012:

	Balance June 30, 2011	Additions	Payments, Refundings & Amortizations	Balance June 30, 2012
		(in thousands)		
Revenue Bonds	$ 935,965	$ 83,785	$ (99,530)	$ 920,220
Unamortized premiums and discounts	19,780	10,324	(2,309)	27,795
Unamortized cost on advance refund of debt	(86,927)	-	3,239	(83,688)
TOTAL	$ 868,818	$ 94,109	$ (98,600)	$ 864,327

Debt service requirements for each of the next five years and in five-year cumulative increments thereafter as of June 30, 2013:

	Principal	Interest	Total
		(in thousands)	
2014	$ 34,365	$ 48,914	$ 83,279
2015	34,000	47,303	81,303
2016	35,615	45,728	81,343
2017	37,250	44,114	81,364
2018	39,230	42,399	81,629
2019-2023	219,980	180,344	400,324
2024-2028	200,125	128,232	328,357
2029-2033	187,935	73,252	261,187
2034-2038	83,980	27,944	111,924
2039-2040	31,225	3,451	34,676
	$ 903,705	$ 641,681	$ 1,545,386

Interest includes interest requirements for fixed rate debt at their stated rate and variable rate debt covered by interest rate swaps at their fixed swap rate.

Redemption Provisions As set forth in the bond indentures, the term bonds are subject to redemption prior to maturity in varying amounts at specific dates. At the option of the Agency, the bonds are also subject to early redemption at specific redemption prices and dates.

Defeased Debt Various bond refundings were undertaken to defease debt and realize future debt service savings. Debt was defeased by using the proceeds of the refunding issues and other available monies to irrevocably place in trust cash and U.S. Government Securities, which together with interest earned thereon, will be sufficient to pay both the interest and the appropriate maturity or redemption value of the refunded bonds as required.

Accordingly, these defeased debt issues have been considered extinguished for financial reporting purposes. At year-end, the following defeased debt remained outstanding:

		2013	2012
		(in thousands)	
Hydroelectric:	Project No. One, 1985 Series A	$ 12,150	$ 12,150
	Project No. One, 1986 Series A	36,960	36,960
	Total Defeased Debt Outstanding	$ 49,110	$ 49,110

Geothermal Project In addition to a federal geothermal leasehold, steam wells, gathering system and related facilities, the project consists of two electric generating stations (Plant 1 and Plant 2). Each plant has two 55 MW (nameplate rating) turbine generator units utilizing low temperature geothermal steam; associated electrical, mechanical and control facilities; a heat dissipation system; a steam gathering system; a transmission tap-line; and, other related facilities. Geothermal steam for the project is derived from the geothermal property, which includes well pads, access roads, steam wells and re-injection wells.

In September 2012, the Agency issued $12,910,000 of fixed rate tax exempt bonds for the purpose of providing funds to finance the costs of acquisition and construction of certain improvements to the project as well as make a contribution to the Debt Service Reserve Account and to pay the costs of issuance of the 2012 Series A Bonds. The bonds are of varying principal amounts ranging from $475,000 to $725,000 through July 1, 2022 and bear interest at 2.289%.

Capital improvements financed include Plant 1 turbine upgrades for both Units 1 and 2 and modifications to the main steam line to reduce pressure losses and increase MW production.

Hydroelectric Project The Agency contracted to finance, manage, construct, and operate Hydroelectric Project Number One for the licensed owner, Calaveras County Water District. In exchange, the Agency has the right to the electric output of the project for 50 years from February 1982. The Agency also has an option to purchase power from the project in excess of the District's requirements for the subsequent 50 years, subject to regulatory approval.

In February 2012, the Agency refunded $88,355,000 principal amount of 1998 Hydroelectric Refunding Revenue Bonds Series A maturing on July 1 in each of the years 2024 through 2032. The refunding was completed through the issuance of $76,665,000 fixed rate tax exempt debt (2012 Series A) and $7,120,000 fixed rate taxable debt (2012 Series B) with yields of 3.05% to 4.32% with varying principal maturities ranging from $4,475,000 to $13,040,000 through July 1, 2032. The refunding is estimated to have decreased project debt service by an estimated $14.4 million over the next 21 years, which results in an estimated economic gain to the Agency of approximately $9.4 million.

As part of a refinancing plan in November 2004, the Agency entered into two forward starting interest rate swaps in an initial notional amount of $85,160,000 and $1,574,000. Payments under the swap agreements with Citigroup Financial Products, Inc. began on April 2, 2008. To complete the refinancing transaction and realize the debt service savings under the 2004 swap agreement, on April 2, 2008 the Agency completed a bond refunding of certain maturities of the 1998 Hydroelectric Refunding Series A bonds totaling

$85,870,000 maturing in 2023 to 2032. These fixed rate bonds were refinanced through the issuance of tax-exempt 2008 Hydroelectric Refunding Series A ($85,160,000) bonds and taxable 2008 Hydroelectric Refunding Series B ($3,165,000) bonds. Both issues are variable interest rate bonds bearing interest at weekly interest rates, payable semi-annually on July 1 and January 1 each year. To support this financing, the Agency entered into two irrevocable direct pay letter of credit agreements with Dexia Credit Local, which were to expire on April 2, 2013. On September 27, 2011, the irrevocable direct pay letter of credit agreements with Dexia Credit Local related to the 2008 Hydroelectric Refunding Series A and B bonds were terminated. Replacement Letters of Credit with Citibank N.A. were issued on the same day. The Citibank letters of credit are for a period of three years and expire on September 27, 2014.

The payment of principal and interest on these issues are not covered by any financial guaranty insurance policies. This 2008 Hydroelectric Refunding and the associated interest rate swaps are estimated to have reduced project debt service by $11.8 million over the next 24 years providing the Agency with an estimated economic gain (difference between the present values of the old and new debt service payments) of approximately $5.9 million.

The Agency has entered into two separate pay-fixed, receive-variable interest rate swaps to produce savings or to result in lower costs over the life of each transaction than what the Agency would have paid using fixed-rate debt. While these derivative instruments carry additional risks, the Agency's swap policy and favorable negotiations have helped to reduce such risks.

	2008 Hydroelectric Refunding Revenue Bonds Forward Starting Swaps			
Associated Interest Rate Swaps starting April 2, 2008	Series A		Series B (Taxable)	
Counterparty to Interest Rate Swap	Citigroup Financial Products Inc.		Citigroup Financial Products Inc.	
Notional Value of Interest Rate Swap	$85,160,000		$1,372,309	
Fair Value--Due from (to) Counterparty	($15,286,969)		$294,816	
Credit Downgrade Required Collateral Posting:				
For Counterparty, Fair Value Above	$10 million		$10 million	
If S&P or Moody's Credit Rating falls to	A+/A1		A+/A1	
For Agency (Credit of Agency's Insurer National Public Finance Guarantee formerly MBIA), Fair Value Above	$10 million		$10 million	
If S&P or Moody's Credit Rating falls to	A+/A1		A+/A1	
Termination Date	July 1, 2032		July 1, 2032	
	Terms	Rates	Terms	Rates
Payments to (from) Counterparty	Fixed	3.819%	Fixed	-5.339%
Variable Payments (from) to Counterparty	54% LIBOR+.54%*	-0.665%	100% of LIBOR*	0.220%
Net Interest Rate Swap Payments		3.154%		-5.119%
Variable-Rate Bond Payments	SIFMA**	0.146%	SIFMA**	0.503%
Effective Interest Rate on Bonds		3.300%		-4.616%

Average to Date: *1-Month London Inter-Bank Offered Rate **Securities Industry and Financial Market Association Municipal Swap Index (formerly the Bond Market Association Municipal Swap Index)

The total fair value of outstanding swap instruments was a net liability of $14,992,000 and $22,342,000 at June 30, 2013 and June 30, 2012, respectively. These amounts are reported as a non-current liability. The interest rate swaps in FY 2013 are both ineffective hedges and considered investment derivative instruments. The change in fair value of ($7.3) million is recorded as interest expense in the Statement of Revenue, Expenses, and Changes in Net Position. In FY 2012 the swap associated with 2008A was considered effective and the change in fair value of $9.8 million was reported as a component of regulatory assets on the Statement of Position. In FY 2012 the swap associated with 2008B was considered ineffective for which the change in fair value of ($0.2) million was reported as interest expense in the Statement of Revenue, Expenses, and Changes in Net Position. The net settlement payments of interest on these investment derivative instruments total $2.6 million which is recorded as interest expense in the Statement of Revenue, Expenses, and Changes in Net Position for both FY 2013 and FY 2012. The value of the swaps noted above reflects the estimated fair value of the swaps at June 30, 2013 as determined by the Agency's financial advisor. The fair value of the swaps will change due to notional amount, amortizations, and interest rate changes.

The following swap agreement risks are common to all the interest rate swaps. The interest rate swaps expose the Agency to basis risk should the relationship between LIBOR and SIFMA converge, changing the synthetic rate on the bonds. If a change occurs that results in the rates moving to convergence, the expected cost savings of the swap may not be realized. The Agency is exposed to interest rate risk on its pay-fixed, receive variable interest rate swaps. Interest rate risk is the risk that changes in interest rates will adversely affect the fair values of the Agency's financial instruments or cash flows. As the LIBOR or SIFMA swap index decreases, the Agency's net payment on swaps increases. In addition, the Agency is exposed to interest rate risk if the counterparty to the swap defaults or if the swap is terminated. The Agency is also exposed to market access risk, the risk that it will not be able to enter credit markets or that credit will become more costly. The Agency's financial rating is tied to the credit strength of the major participants of the specific project for which each financial instrument is issued. The Agency is also exposed to market access risks caused by disruptions in the municipal bond market.

To mitigate the potential for credit risk, the swap counterparties are required by the agreement to post collateral should the fair value exceed certain thresholds as shown above. At June 30, 2013, credit ratings of the counterparties to the swaps were as follows:

Swap Counterparty & Agency's Insurer	Standard & Poor's	Moody's
Citigroup Financial Products Inc.	A-	Baa2
National Public Finance Guarantee formerly MBIA (the Agency's insurer)	A	Baa1

The swaps utilized the International Swap Dealers Association (ISDA) Master Agreement, which includes standard termination events, such as failure to pay and bankruptcy. However, an additional provision under the Schedule to the ISDA Master Agreement allows the swap to be terminated by the Agency if the counterparty's credit rating falls below A- by Standard & Poor's or A3 by Moody's. If a swap is terminated, the applicable bonds would no longer carry a synthetic fixed interest rate. In addition, if a swap has a negative fair value at the time of an early termination, the Agency would be liable to the counterparty for a payment equal to the swap's fair value.

Combustion Turbine Project The original project consisted of five combustion turbine units, each nominally rated at approximately 25 megawatts. Concurrent with the final project bond maturity, two units located in Roseville were acquired by an Agency member. The remaining project consists of two units in Alameda and one in Lodi. The project provides capacity during peak load periods and emergency capacity reserves. Excess capacity and energy from the project are also sold to other entities from time to time.

Capital Facilities Project The project consists of one 49.9 megawatt natural gas-fired steam injected combustion turbine generator unit located in Lodi, California. Wastewater is reclaimed from the City of Lodi's White Slough water pollution control facility, processed to eliminate contaminants, and used in the turbine to produce steam for power enhancement and emissions control.

Lodi Energy Center The Agency has constructed a new 296 MW base load, combined cycle, natural gas-fired, combustion turbine generating station (one gas turbine and one steam turbine) located in Lodi, California, next to the Capital Facilities Project discussed above. Construction began in August 2010 with commercial operation in November 2012. Pursuant to the Lodi Energy Center Power Sales Agreement, the Agency agreed to construct and operate the LEC and has sold all of the capacity and energy of the LEC to thirteen participants (including four non-members) in accordance with their respective Generation Entitlement Shares (GES). Each participant has agreed to unconditionally provide for its share of the costs of construction of the LEC and all capital improvements and to pay its share of the operation and maintenance expenses based on its GES. The LEC will be operated and maintained by the Agency under the direction of the LEC Project Management and Operations Agreement among the Agency and the LEC Project Participants.

Lodi Energy Center Revenue Bonds, Issue One provided financing for 11 project participants with 55.7857% GES. Lodi Energy Center Revenue Bonds, Issue Two provided financing for the California Department of Water Resources 33.5% GES. The Modesto Irrigation District elected to provide its own financing for its 10.7143% GES of the costs of construction of the project. Modesto Irrigation District is not liable for any Agency debt service obligations for the project.

The Issue One Series B and the Issue Two Series B bonds were issued as Taxable Subsidy Bonds constituting Build America Bonds (BABs) for the purposes of the American Recovery and Reinvestment Act of 2009. The Act provides for a direct payment to the Agency from the federal government equal to 35% of the interest costs. Such payments have been and may continue to be affected by the federal government budget sequestration.

NOTE E -- RETIREMENT PLAN

The Agency is a participating public employer in the California Public Employees Retirement System (CalPERS) Local Miscellaneous Employees' Retirement Plan, which is an agent multiple-employer public employee defined benefit pension plan. CalPERS provides retirement and disability benefits, annual cost-of-living adjustments, and death benefits to plan members and beneficiaries. CalPERS acts as a common investment and administrative agent for participating public entities within the State of California. Benefit provisions and all other requirements are established by state statute and Agency resolution. CalPERS issues a separate comprehensive annual financial report, which is available from the CalPERS' Executive Office, 400 P Street, Sacramento, California 95814.

The Agency makes the plan contributions required of its employees on their behalf and for their account. The Agency is required to contribute at an actuarially determined rate of annual covered payroll. The contribution requirements of plan members and the Agency are established and may be amended by CalPERS.

In 2012, the Public Employees' Pension Reform Act (PEPRA) became law that implemented new benefit formulas and final compensation period, as well as, new contribution requirements for new employees hired on or after January 1, 2013 who meet the definition of new member under PEPRA. Employees hired prior to January 1, 2013 and those new employees not meeting the PEPRA definition of new member are considered classic employees.

Summary of certain plan provisions and benefits in effect for fiscal year ended June 30, 2013:

Required service for eligibility	5 full-time years
Benefit payments (% of highest 36 consecutive months' annual salary)	Monthly for life
Minimum retirement age	50
Classic Members:	
Monthly benefit	2.00% @ age 50 to 2.50% @ age 55 & up
Required employee contribution rate (w/o employer pickup)	8.000%
New Members:	
Monthly benefit	2.00% @ age 60 to 2.50% @ age 67 & up
Required employer contribution rate (w/o employer pickup)	6.25%
Required employer contribution rates	9.841% normal service 18.423% amortization bases
Actuarial annual required contribution (based on estimated payroll)	$4,965,289

Prior to joining the CalPERS retirement system, the Agency agreed to pay (pick up) 50% of prior service cost for the then existing employees. In separate agreements, the Agency has also agreed to pay (pickup) a portion of the various employee groups' required annual contribution. Actual employer portion contributions to the plan totaled $775,744 and $804,569 for fiscal years 2013 and 2012, respectively. The Agency's annual required contribution (based on actuarially established rates) was determined as part of a June 30, 2011, actuarial valuation using the entry age normal actuarial cost method. The primary actuarial assumptions included a 7.50% annual investment rate of return (net of administrative expenses); forecasted annual salary increases that vary by age, service and type of employment ranging from 3.30% to 14.20%; a 3.00% overall annual payroll growth; an individual salary growth of 2.75%; an annual production growth of .25%; and, an inflation component of 2.75%. A 15-year rate smoothed market approach is used to spread investment returns. At fiscal year end June 30, 2013, the Agency had 152 eligible active employees and 99 retirees drawing benefits under this program.

Trend Information for Agency CalPERS Retirement Plan

Fiscal Year Ending	Annual Pension Cost (APC)	Percentage of APC Contributed	Net Pension Obligation
June 30, 2009	$ 2,890,336	100.0%	-
June 30, 2010	$ 3,320,661	100.0%	-
June 30, 2011	$ 3,842,787	100.0%	-
June 30, 2012	$ 4,825,514	100.0%	-
June 30, 2013	$ 4,965,785	100.0%	-

Funded Status of the Agency CalPERS Retirement Plan

Actuarial Valuation Date	Actuarial Accrued Liability (a)	Actuarial Value of Assets (b)	Actuarial Accrued Unfunded Liability (a) - (b)	Funded Ratio (b) / (a)	Annual Covered Payroll (c)	Unfunded Actuarial Accrued Liability as % of Payroll [(a) – (b)] / (c)
June 30, 2007	$ 54,443,624	$ 28,955,468	$ 25,488,156	53.2%	$ 15,378,571	165.7%
June 30, 2008	$ 66,571,897	$ 34,498,660	$ 32,073,237	51.8%	$ 15,930,785	201.3%
June 30, 2009	$ 80,909,833	$ 39,535,328	$ 41,374,505	48.9%	$ 16,871,454	245.2%
June 30, 2010	$ 92,905,054	$ 46,778,990	$ 46,126,064	50.4%	$ 16,258,205	283.7%
June 30, 2011	$100,525,265	$ 53,296,953	$ 47,231,312	53.0%	$ 17,682,597	267.1%

Initial unfunded liabilities are amortized over a closed period that depends on the plan's date of entry into CalPERS. The unfunded actuarial accrued liability is being amortized as a level percentage of projected payroll on a closed basis. All changes in liability due to plan amendments, changes in actuarial assumptions, or changes in actuarial methodology are amortized separately over a 20-year period. The average remaining amortization period at the June 30, 2011 valuation date was approximately 24 years. Operating gains and losses of the plan are amortized over a 30-year rolling period, which results in an amortization of about 6% of unamortized gains and losses each year. If the plan's accrued liability exceeds the actuarial value of plan assets, then the amortization payment on the total unfunded liability may not be lower than the payment calculated over a 30-year amortization period. CalPERS actuarial valuations become available approximately two years after the Agency's fiscal year-end.

NOTE F -- OTHER POST EMPLOYMENT BENEFITS (OPEB)

The Agency contracts with the CalPERS under the Public Employees' Medical and Hospital Care Act (PEMHCA) for employee medical insurance. In connection with this plan, the Agency provides medical insurance to all active employees and their families, as well as all qualified retirees (and spouses), subject to certain limitations. The Agency has maintained an actuarially based restricted fund for the sole purpose of paying medical insurance premiums for qualified retired employees (and spouses) participating in the CalPERS medical plan. In 2007, the Agency became a participant in the CalPERS California Employers' Retiree Benefit Trust (CERBT), a pre-funding OPEB plan, which is an irrevocable multi-employer trust and plan consisting of an aggregation of single-employer plans, with pooled administrative and investment functions. The Agency makes actuarially determined Annual Required Contributions (ARC) to this OPEB plan. The ARC represents the forecast funding level to cover normal cost each year and amortize any unfunded actuarial liabilities (or funding excess) over a period not to exceed 30 years. Actuarial valuations of the fund are obtained every two years, as required by CalPERS.

Summary of certain plan provisions and benefits in effect during fiscal year ended June 30, 2013:

Required service for eligibility	10 full-time years
Minimum retirement age	50
Benefit payments	Monthly for life
Vesting for eligible employees	50% at 10 years; 5%/year after
Maximum monthly benefit	PERS Choice Premium

The annual required contribution and funded status of the OPEB plan were determined based on current cost trends of the CalPERS health plans in which the employees currently participate at the time of the actuarial valuation. The June 30, 2013 actuarial valuation was prepared on the basis of the OPEB assumption model, as prescribed by the CalPERS, in effect at the time of the valuation. At fiscal year-end June 30, 2013, the Agency had 152 active eligible employees and 110 retirees drawing benefits under this program.

Trend Information for the OPEB Plan

Fiscal Year Ending	Annual OPEB Cost	Percentage of OPEB Cost Contributed	Net OPEB Obligation
June 30, 2009	$ 718,982	100.0%	-
June 30, 2010	$ 770,469	100.0%	-
June 30, 2011*	$ 961,896	100.0%	-
June 30, 2012	$ 1,016,826	100.0%	-
June 30, 2013	$ 1,049,873	100.0%	-

Funded Status of the OPEB Fund

Actuarial Valuation Date	Actuarial Accrued Liability (a)	Actuarial Value of Assets (b)	Actuarial Accrued Unfunded Liability (a) - (b)	Funded Ratio (b) / (a)	Annual Covered Payroll (c)	Unfunded Actuarial Accrued Liability as % of Payroll [(a) – (b)] / (c)
June 30, 2008	$ 16,114,250	$ 12,213,980	$ 3,900,270	75.8%	$ 15,491,511	25.2%
June 30, 2010	$ 18,936,156	$ 13,975,353	$ 4,960,803	73.8%	$ 16,355,901	30.3%
June 30, 2011*	$ 21,599,763	$ 14,464,987	$ 7,134,776	67.0%	$ 16,672,248	42.8%
June 30, 2013	$ 22,477,396	$ 17,529,070	$ 4,948,326	78.0%	$ 17,564,711	28.2%

The funded status of the plan and the annual required contributions are subject to periodic revision based on actual results, changes in assumptions or plan provisions, and new estimates of expected future circumstances. Future actuarial valuations will be performed every two years, as prescribed by CalPERS.

The Agency's annual required contribution (based on actuarially established rates) was determined as part of a June 30, 2013, actuarial valuation using the entry age normal actuarial cost method. The primary actuarial assumptions included: valuation using the Entry Age Normal Cost Method; 7.61% annual discount rate; overall payroll growth of 3.25%; 3.00% inflation; and 4.25% maximum employer contribution increase.

* The discount rate was changed from 7.75%, which was used in all prior year's actuarial valuations, to 7.61% for the June 30, 2011 and later actuarial valuation, as prescribed by CalPERS.

NOTE G -- COMMITMENTS AND CONTINGENCIES

Power Exchange Agreement On behalf of certain of its members, the Agency has a seasonal exchange agreement with Seattle City Light for 60 megawatts of summer capacity and 90,580 megawatt hours of energy in exchange for a return of 46 megawatts of capacity and 108,696 megawatt hours of energy in the winter. The agreement terminates in May 2018.

Power Purchase Contracts The Agency had commitments of approximately $57.9 million in connection with various power purchase contracts as of June 30, 2013. The contracts, extending through December 2016, are normal purchases at agreed to contract prices for fixed quantities of energy. Certain of the Agency's members have individually entered into certain other long-term contracts, which the Agency dispatches and schedules for them. See Note B - Summary of Significant Accounting Policies.

Combustion Turbine Fuel Supply Agreements The Agency has entered into the following agreements to provide natural gas fuel supply for use in the combustion turbine projects:

- A 30-year agreement terminating in November 2023 with the Pacific Gas Transmission Company and its partners in a gas pipeline between Alberta, Canada and northern California. The estimated minimum annual gas transmission commitment is approximately $1.5 million.

- On behalf of the participants in the Combustion Turbine Number One and the Capital Facilities project, the Agency entered into an agreement with Sequent Energy Management, L.P. effective January 1, 2012 to provide gas supply, scheduling, nomination, balancing and settlement services for the management of the Agency's pipeline capacity. In June 2012, Sequent provided the Agency with a six-month notice of termination, as a result of which the Sequent Energy Management, L.P. agreements terminated on December 31, 2012.

  The Agency entered into a replacement agreement with EDF Trading North America, LLC effective January 1, 2013 to provide gas supply, scheduling, nomination, balancing and settlement services for the management of the Agency's pipeline capacity. The contract is automatically renewed each year on January 1, unless terminated earlier by six months written notice by either party.

- The Agency and J.P. Morgan Ventures Energy Corporation have entered into an agreement to provide the gas supply and nomination, imbalance, and settlement services for the Agency's Lodi Energy Center project, which began operations at the end of November 2012. Subsequent to an initial one year term, the contract may be terminated with a six-month notice of termination.

- The Agency had approximately $14.7 million of gas purchase commitments at June 30, 2013. The commitments, extending through December 2016, are normal purchases at agreed to prices for fixed quantities of gas.

Western Area Power Administration Base Resource A number of the Agency's members, who have an aggregate 17.53465% share of the Base Resource Contract with the Western Area Power Administration to receive electric power from the Central Valley Project in California, have assigned their shares to the Agency in order to create a power resource portfolio for the mutual benefit of participating Agency members. The assignments terminate the earlier of December 31, 2024 or 60 days after Western approves a reassignment.

Geothermal Royalties Under terms of federal geothermal leasehold agreements, the Agency is required to pay royalties to the United States (U.S.) on the value of geothermal steam produced. Currently, the effective rate of such royalties is 3.6% of an amount based on the Agency's monthly weighted average cost of third-party wholesale electricity purchases made by Agency members participating in the Geothermal Project. The U.S. Department of the Interior, Office of Natural Resources Revenue maintains the right to periodically review and withdraw their approval or to change this methodology should operations, market conditions, or Federal regulations change.

Geothermal Steam Production & Decommissioning Steam for the Agency's geothermal plants comes from lands in the Geysers area, which, are leased by the Agency from the federal government. The Agency 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, by April 1988, for the purpose of slowing the decline in the steam field capability, the Agency changed its steam field production from base-load to load-following and reduced average annual generation. These changes were effective in reducing the decline in steam production.

Beginning in 1991, along with other steam field operators in the area, the Agency began implementing various operating strategies to further reduce the rate of decline in steam production. The Agency has modified both steam turbine units at Plant 1 and the associated steam collection system to enable generation with lower pressure steam at higher mass-flow rates to optimize the utilization of the available steam resource.

The Agency also entered into agreements with other producers 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 the Agency and the other Geysers steam field operator for injection into the steam field. A second pipeline enhancement project to further augment the wastewater injection program was completed in 2004.

Based on current operating protocols and forecasted operations, the Agency expects both the average and peak capacity to continue to decrease, reaching approximately 70 MWG (megawatts gross) by calendar year 2037.

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, the Agency has preferential right to renew the leasehold for a second term. The leasehold also requires the Agency to remove its leasehold improvements including the geothermal plants and steam gathering system when and if the Agency abandons the leasehold. These decommissioning costs are currently estimated to total approximately $24.1 million. The Agency has been collecting monies to pay the expected decommissioning costs since 2007 and currently holds approximately $8.1 million in a reserve for such purpose as of June 30, 2013.

CLAIMS AND LITIGATION

California Energy Crisis During 2000 and 2001, California experienced extreme fluctuations in the prices and supplies of natural gas and electricity in much of the State. While there has been progress in addressing these issues, uncertainty remains. As a result, no assurance can be given that measures undertaken, together with measures to be taken in the future, will prevent the recurrence of shortages, price volatility or other energy problems that have adversely affected California electric utilities in the past. The Agency has settled with the plaintiffs in related litigation, and that settlement has been approved by FERC, there are still some claims by others that remain ongoing. Although the Agency considers these claims to be lacking in merit, no assurance thereof can be given until all proceedings are finally concluded.

Greenhouse Gas (GHG) Emissions The California Global Warming Solutions Act of 2006 (also known as California Assembly Bill 32 or AB 32) requires the gradual reduction of state-wide GHG emissions to the 1990 level by 2020. The California Air Resources Board (CARB) is the state agency charged with monitoring GHG levels and adopting regulations to implement and enforce AB 32. The CARB has approved various regulations, including regulations that established a state-wide, comprehensive ''cap-and-trade'' program that sets a gradually declining limit (or ''cap'') on the amount of GHGs that may be emitted by the major sources of GHG emissions each year. GHG emissions are measured in metric tons (MT) of carbon dioxide-equivalent greenhouse gases (CO_{2e}) per year. The cap and trade program's first two-year compliance period, which began January 1, 2013, applies to the electricity generation and large industrial sectors. The next compliance period, from January 1, 2015 through December 31, 2017, will expand to include the natural gas supply and transportation sectors, effectively covering all the capped sectors until 2020.

The Agency's Lodi Energy Center gas plant and electricity imports (purchased power) are subject to the compliance rules established by CARB for the cap-and-trade program. As such, the Agency participates in quarterly auctions to acquire sufficient carbon allowances to cover its compliance obligations or receives transfers of required carbon allowances from its project participants. At June 30, 2013 the Agency had a cumulative compliance obligation of 272,977 MT with 407,827 MT of acquired allowances to meet its compliance obligation.

Other Factors Affecting the Electric Utility Industry Electric industry market participants, such as the Agency and its members, continue to face numerous potential risks and uncertainties including, but not limited to, significant volatility in energy prices and increased transmission and ancillary services costs; new federal and state renewable energy, operating efficiency, and environmental standards; and, global pressures on economic and financial market conditions. The Agency and its members continue to study and to take various actions in an effort to mitigate and manage these risk and uncertainties. However, the Agency cannot predict either the ultimate outcome of these ongoing changes or whether such outcome will have a material adverse effect on its financial position or results of operations.

Other Legal Matters The Agency is engaged in various legal proceedings before federal and state courts and various administrative tribunals incidental to the Agency's operations.

Based on its review of the aforementioned proceedings with outside legal counsel, the Agency believes that the ultimate aggregate liability, if any, resulting from these proceedings will not have a materially adverse effect on the combined financial position or results of operations of the Agency.

OTHER FINANCIAL INFORMATION

COMBINING STATEMENT OF NET POSITION

NORTHERN CALIFORNIA POWER AGENCY
AND ASSOCIATED POWER CORPORATIONS

(000's omitted)

June 30, 2013

	GENERATING & TRANSMISSION RESOURCES									
ASSETS	Geothermal	Hydroelectric	Multiple Capital Facilities	CT No. One	Lodi Energy Center	Transmission	Purchased Power & Transmission	Associated Member Services	Other Agency	Combined
CURRENT ASSETS										
Cash and cash equivalents	$ 1	$ -	$ 1	$ 1	$ 86	$ -	$ -	$ 415	$ 59,007	$ 59,511
Investments	-	-	-	-	-	-	-	-	7,452	7,452
Accounts receivable										
Participants	-	-	-	33	-	-	90	-	84	207
Other	109	29	-	6	1,551	-	1,247	-	161	3,103
Interest receivable			-	2	4	-	19	-	13	38
Inventory and supplies - at average cost	3,040	1,044	642	1,401	991	-	-	-	-	7,118
Prepaid expenses	321	286	32	39	359	-	-	4	32	1,073
Due from Agency and other programs*	12,337	12,747	2,363	(938)	7,458	2	21,989	3,565	(59,523)	-
TOTAL CURRENT ASSETS	15,808	14,106	3,038	544	10,449	2	23,345	3,984	7,226	78,502
RESTRICTED ASSETS										
Cash and cash equivalents	5,097	17,782	962	-	17,746	-	1,324	-	16,200	59,111
Investments	15,538	36,444	4,505	-	10,560	-	16,553	-	70,950	154,550
Interest receivable	15	80	16	-	6	-	-	-	29	146
TOTAL RESTRICTED ASSETS	20,650	54,306	5,483	-	28,312	-	17,877	-	87,179	213,807
ELECTRIC PLANT										
Electric plant in service	564,445	393,511	64,826	36,146	423,355	7,736	-	329	4,399	1,494,747
Less accumulated depreciation	(526,969)	(214,987)	(37,303)	(33,611)	(8,536)	(7,683)	-	(168)	(1,887)	(831,144)
	37,476	178,524	27,523	2,535	414,819	53	-	161	2,512	663,603
Construction work-in-progress	12,467	-	-	-	-	-	-	-	-	12,467
TOTAL ELECTRIC PLANT	49,943	178,524	27,523	2,535	414,819	53	-	161	2,512	676,070
OTHER ASSETS										
Regulatory assets	16,611	159,383	17,020	-	6,788	(53)	-	-	-	199,749
Unamortized debt issuance expenses	549	6,331	432	-	3,564	-	-	-	-	10,876
Preliminary survey and investigation costs	-	113	-	-	-	-	-	166	-	279
TOTAL OTHER ASSETS	17,160	165,827	17,452	-	10,352	(53)	-	166	-	210,904
TOTAL ASSETS	$ 103,561	$ 412,763	$ 53,496	$ 3,079	$ 463,932	$ 2	$ 41,222	$ 4,311	$ 96,917	$ 1,179,283

* Eliminated in Combination

COMBINING STATEMENT OF NET POSITION

NORTHERN CALIFORNIA POWER AGENCY
AND ASSOCIATED POWER CORPORATIONS

(000's omitted)

	June 30, 2013									
	GENERATING & TRANSMISSION RESOURCES									
LIABILITIES	Geothermal	Hydroelectric	Multiple Capital Facilities	CT No. One	Lodi Energy Center	Transmission	Purchased Power & Transmission	Associated Member Services	Other Agency	Combined
CURRENT LIABILITIES										
Accounts payable	$ 823	$ 990	$ 22	$ 64	$ 3,995	$ -	$ 13,393	$ 82	$ 6,547	$ 25,916
Accounts and retentions payable - restricted for construction	-	-	-	-	696	-	-	-	-	696
Operating reserves	4,340	250	533	185	10,951	-	-	-	-	16,259
Member advances	791	-	-	-	-	-	-	367	-	1,158
Current portion of long-term debt	3,060	19,375	3,290	-	8,640	-	-	-	-	34,365
Accrued interest	963	9,781	980	-	2,000	-	-	-	-	13,724
TOTAL CURRENT LIABILITIES	9,977	30,396	4,825	249	26,282	-	13,393	449	6,547	92,118
NON-CURRENT LIABILITIES										
Operating reserves and other deposits	8,151	10,672	-	-	86	-	17,896	415	87,295	124,515
Regulatory liability	34,234	4,294	1,318	3,976	49,152	2	-	163	2,629	95,768
Interest rate swap liability	-	14,992	-	-	-	-	-	-	-	14,992
Long-term debt, net	41,578	345,063	46,909	-	382,935	-	-	-	-	816,485
TOTAL NON-CURRENT LIABILITIES	83,963	375,021	48,227	3,976	432,173	2	17,896	578	89,924	1,051,760
TOTAL LIABILITIES	93,940	405,417	53,052	4,225	458,455	2	31,289	1,027	96,471	1,143,878
NET POSITION										
Net investment in capital assets	(5,892)	(33,506)	(6,491)	-	(9,745)	-	-	2	2	(55,630)
Restricted	9,021	40,720	4,503	-	11,126	-	(19)	(500)	(115)	64,736
Unrestricted	6,492	132	2,432	(1,146)	4,096	-	9,952	3,782	559	26,299
TOTAL NET POSITION	9,621	7,346	444	(1,146)	5,477	-	9,933	3,284	446	35,405
TOTAL LIABILITIES AND NET POSITION	$ 103,561	$ 412,763	$ 53,496	$ 3,079	$ 463,932	$ 2	$ 41,222	$ 4,311	$ 96,917	$ 1,179,283

* Eliminated in Combination

COMBINING STATEMENTS OF REVENUES, EXPENSES AND CHANGES IN NET POSITION

NORTHERN CALIFORNIA POWER AGENCY
AND ASSOCIATED POWER CORPORATIONS

(000's omitted)

For the Twelve Months Ending June 30, 2013

	GENERATING & TRANSMISSION RESOURCES									
	Geothermal	Hydroelectric	Multiple Capital Facilities	CT No. One	Lodi Energy Center	Transmission	Purchased Power & Transmission	Associated Member Services	Other Agency	Combined
SALES FOR RESALE										
Participants	$ 35,873	$ 52,484	$ 8,529	$ 3,040	$ 36,097	$ -	$ 138,513	$ 15,988	$ 99	$ 290,623
Other third-party	3,566	-	-	-	26,007	-	20,750	22	-	50,345
TOTAL SALES FOR RESALE	39,439	52,484	8,529	3,040	62,104	-	159,263	16,010	99	340,968
OPERATING EXPENSES										
Purchased power	-	-	-	-	-	-	101,517	-	-	101,517
Transmission	-	-	-	-	1,004	-	51,385	-	-	52,389
Depreciation	10,135	9,405	2,226	181	8,536	16	-	50	131	30,680
Operations	20,837	2,836	2,094	585	25,081	-	1,260	9,475	-	62,168
Administrative and general	4,570	3,831	421	320	1,855	-	650	5,666	(5)	17,308
Maintenance	8,760	4,207	1,024	1,470	6,708	-	-	31	-	22,200
Intercompany (sales) purchases, net *	(396)	246	50	(11)	166	-	-	(55)	-	-
TOTAL OPERATING EXPENSES	43,906	20,525	5,815	2,545	43,350	16	154,812	15,167	126	286,262
NET OPERATING REVENUES	(4,467)	31,959	2,714	495	18,754	(16)	4,451	843	(27)	54,706
OTHER (EXPENSES) REVENUES										
Interest expense	(1,748)	(17,132)	(2,241)	-	(16,647)	-	-	(4)	-	(37,772)
Interest income	81	106	39	-	143	-	85	5	333	792
Capitalized interest	-	-	-	-	6,320	-	-	-	-	6,320
Amortization	(39)	(355)	(34)	-	(37)	-	-	-	-	(465)
Other	3,149	729	997	2	104	-	281	373	264	5,899
TOTAL OTHER REVENUES (EXPENSES)	1,443	(16,652)	(1,239)	2	(10,117)	-	366	374	597	(25,226)
FUTURE RECOVERABLE/(REFUNDABLE) AMOUNTS	5,492	(12,579)	(1,224)	-	(2,977)	16	-	-	-	(11,272)
REFUNDS TO PARTICIPANTS	(5,505)	(1,927)	255	3	(182)	-	(2,116)	(1,486)	(242)	(11,200)
INCREASE (DECREASE) IN NET POSITION	(3,037)	801	506	500	5,478	-	2,701	(269)	328	7,008
NET POSITION, Beginning of year	12,658	6,544	(62)	(1,646)	-	-	7,232	3,553	118	28,397
NET POSITION, End of Year	$ 9,621	$ 7,345	$ 444	$ (1,146)	$ 5,478	$ -	$ 9,933	$ 3,284	$ 446	$ 35,405

* Eliminated in Combination

OTHER FINANCIAL INFORMATION

COMBINING STATEMENTS OF CASH FLOW

NORTHERN CALIFORNIA POWER AGENCY
AND ASSOCIATED POWER CORPORATIONS
(000's omitted)

	For the Year Ended June 30, 2013									
	GENERATING & TRANSMISSION RESOURCES									
	Geothermal	Hydroelectric	Mulitple Capital Facilities	CT No. One	Lodi Energy Center	Transmission	Purchased Power & Transmission	Associated Member Services	Other Agency	Combined Total
CASH FLOWS FROM OPERATING ACTIVITIES:										
Received from participants	$ 36,687	$ 52,506	$ 8,439	$ 2,651	$ 46,450	$ -	$ 138,407	$ 15,002	$ 3,216	$ 303,358
Received from others	3,839	1	-	(2)	24,456	-	20,145	163	316	48,918
Payments for employee services	(8,850)	(3,918)	(1,476)	(566)	(11,872)	-	-	(2,279)	(1,740)	(30,701)
Payments to suppliers for goods & services	(20,894)	(5,180)	(2,043)	(1,627)	(28,991)	-	(156,307)	(11,750)	(2,773)	(229,565)
Payments from(to) other programs *	396	(246)	(49)	12	(166)	-	(1)	54	-	-
NET CASH FROM OPERATING ACTIVITIES	11,178	43,163	4,871	468	29,877	-	2,244	1,190	(981)	92,010
CASH FLOWS FROM INVESTING ACTIVITIES										
Proceeds from maturities & sales of investments	12,144	40,919	4,348	-	30,191	-	12,510	-	151,497	251,609
Interest received	97	261	43	-	182	-	110	12	284	989
Purchase of investments	(21,270)	(48,078)	(4,451)	-	(31,265)	-	(16,552)	(8)	(149,155)	(270,779)
Payments from(to) other programs *	-	-	-	-	-	-	-	-	-	-
NET CASH FROM INVESTING ACTIVITIES	(9,029)	(6,898)	(60)	-	(892)	-	(3,932)	4	2,626	(18,181)
CASH FLOWS FROM CAPITAL AND RELATED FINANCING ACTIVITIES										
Expenditures for debt issuance costs	(173)	-	-	-	-	-	-	-	-	(173)
Acquisition and construction of electric plant	(12,188)	(338)	-	-	(4,074)	-	-	-	(228)	(16,828)
Principal repayment on long-term debt	(2,175)	(15,600)	(3,140)	-	(8,315)	-	-	(4)	-	(29,234)
Interest paid on long-term debt	(1,768)	(19,983)	(2,383)	-	(17,933)	-	-	-	-	(42,067)
Proceeds from bond issues	12,910	-	-	-	-	-	-	-	-	12,910
Payments to refund debt	-	-	-	-	-	-	-	-	-	-
Payments from(to) other programs *	-	-	-	-	-	-	-	-	-	-
NET CASH FROM CAPITAL AND RELATED FINANCING ACTIVITIES	(3,394)	(35,921)	(5,523)	-	(30,322)	-	-	(4)	(228)	(75,392)
CASH FLOWS FROM NON-CAPITAL AND RELATED FINANCING ACTIVITIES										
Advances returned to participants	-	-	-	-	-	-	-	-	-	-
Preliminary survey and investigation costs	-	-	-	-	-	-	-	-	-	-
Other proceeds	3,149	728	997	2	105	-	281	373	265	5,900
Refunds to Participants	(5,505)	(1,926)	255	3	(182)	-	(2,117)	(1,486)	(242)	(11,200)
Payments from(to) other programs *	1,258	(1,198)	(516)	(473)	(7,654)	-	3,223	338	5,022	-
NET CASH FROM NON-CAPITAL AND RELATED FINANCING ACTIVITIES	(1,098)	(2,396)	736	(468)	(7,731)	-	1,387	(775)	5,045	(5,300)
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(2,343)	(2,052)	24	-	(9,068)	-	(301)	415	6,462	(6,863)
Beginning of year	7,441	19,834	939	1	26,900	-	1,625	-	68,745	125,485
End of year	$ 5,098	$ 17,782	$ 963	$ 1	$ 17,832	$ -	$ 1,324	$ 415	$ 75,207	$ 118,622

* Eliminated in Combination

OTHER FINANCIAL INFORMATION

COMBINING STATEMENTS OF CASH FLOW

NORTHERN CALIFORNIA POWER AGENCY
AND ASSOCIATED POWER CORPORATIONS
(000's omitted)

	For the Year Ended June 30, 2013									
	GENERATING & TRANSMISSION RESOURCES									
	Geothermal	Hydroelectric	Mulitple Capital Facilities	CT No. One	Lodi Energy Center	Transmission	Purchased Power & Transmission	Associated Member Services	Other Agency	Combined
RECONCILIATION OF NET OPERATING REVENUES TO NET CASH PROVIDED BY OPERATING ACTIVITIES										
Net operating revenues	$ (4,468)	$ 31,959	$ 2,715	$ 496	$ 18,755	$ (17)	$ 4,451	$ 841	$ (26)	$ 54,706
Adjustments to reconcile net operating revenues to net cash from operating activities:										
Depreciation	10,136	9,403	2,226	181	8,536	17	-	50	131	30,680
	5,668	41,362	4,941	677	27,291	-	4,451	891	105	85,386
Cash flows impacted by changes in:										
Accounts receivable	273	1	-	(36)	(1,551)	-	(1,155)	235	3,511	1,278
Inventory and prepaids	(97)	(28)	(2)	(2)	(1,350)	-	(1)	8	170	(1,302)
Operating reserves & other deposits	4,172	1,252	-	124	9,737	-	460	414	(5,659)	10,500
Preliminary Survey and Investigation Costs	-	-	-	-	-	-	-	(26)	-	(26)
Regulatory assets	-	-	-	(1,452)	-		-	-	-	(1,452)
Regulatory liabilities	814	22	(90)	1,097	10,352	-	(16)	(81)	(76)	12,022
Accounts payable	348	554	22	60	(14,602)	-	(1,495)	(251)	968	(14,396)
NET CASH FROM OPERATING ACTIVITIES	$ 11,178	$ 43,163	$ 4,871	$ 468	$ 29,877	$ -	$ 2,244	$ 1,190	$ (981)	$ 92,010
CASH AND CASH EQUIVALENTS AS STATED IN THE COMBINED BALANCE SHEETS:										
Cash and cash equivalents - current	$ 1	$ -	$ 1	$ 1	$ 86	$ -	$ -	$ 415	$ 59,007	$ 59,511
Cash and cash equivalents - restricted	5,097	17,782	962	-	17,746	-	1,324	-	16,200	59,111
	$ 5,098	$ 17,782	$ 963	$ 1	$ 17,832	$ -	$ 1,324	$ 415	$ 75,207	$ 118,622

GENERATION ENTITLEMENT SHARES - UNAUDITED

NORTHERN CALIFORNIA POWER AGENCY
AND ASSOCIATED POWER CORPORATIONS

	Table of Generation Entitlement Shares					LEC Debt Shares	
	Geothermal Project No. 3	Hydroelectric Project No. One	Capital Facilities Project	Combustion Turbine No. One	Lodi Energy Center (LEC)	LEC Indenture Group A	LEC Indenture Group B
NCPA Member Participants:							
Alameda	16.8825%	10.0000%	19.0000%	21.8200%			
BART					6.6000%	11.8310%	
Biggs	0.2270%			0.1970%	0.2679%	0.4802%	
Gridley	0.3360%			0.3500%	1.9643%	3.5212%	
Healdsburg	3.6740%	1.6600%		5.8330%	1.6428%	2.9448%	
Lodi	10.2800%	10.3700%	39.5000%	13.3930%	9.5000%	17.0295%	
Lompoc	3.6810%	2.3000%	5.0000%	5.8330%	2.0357%	3.6491%	
Palo Alto		22.9200%					
Plumas-Sierra REC	0.7010%	1.6900%		1.8170%	0.7857%	1.4084%	
Roseville	7.8830%	12.0000%	36.5000%				
Santa Clara	44.3905%	37.0200%		41.6670%	25.7500%	46.1588%	
Ukiah	5.6145%	2.0400%		9.0900%	1.7857%	3.2010%	
Other Participants:							
Azuza					2.7857%	4.9936%	
California Dept. of Water Resources					33.5000%		100.0000%
Modesto Irrigation District					10.7143%		
Power & Water Resources Pooling Agency					2.6679%	4.7824%	
Turlock Irrigation District	6.3305%						
	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.000%	100.000%
	Note A	Note A, B		Note A	Note B		

Note A: Project Entitlement shares are after transfers among participants.

Note B: Project Generation Shares may vary from project cost shares due to varied financing and fuel supply arrangements.

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APPENDIX C

BOOK-ENTRY ONLY SYSTEM

The Depository Trust Company, New York, New York ("DTC") acts as securities depository for the 2008 Bonds. The 2008 Bonds were 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 certificate for each maturity of the 2008 Bonds of each Series, in the aggregate principal amount of such maturity and Series, has been 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 Direct and Indirect Participants are on file with the Securities and Exchange Commission. More information about DTC can be found at www.dtcc.com. The information on this website is not incorporated herein by reference.

Purchases of 2008 Bonds under the DTC book-entry system must be made by or through Direct Participants, which will receive a credit for the 2008 Bonds on DTC's records. The ownership interest of each actual purchaser of each 2008 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 2008 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 2008 Bonds, except in the event that use of the book-entry system for the 2008 Bonds is discontinued.

To facilitate subsequent transfers, all 2008 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 the 2008 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 2008 Bonds; DTC's records reflect only the identity of the Direct Participants to whose accounts such 2008 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 the 2008 Bonds may wish to take certain steps to augment the transmission to them of notices of significant events with respect to the 2008 Bonds, such as redemptions, tenders, defaults, and proposed amendments to the 2008 Bond documents. For example, Beneficial Owners of the 2008 Bonds may wish to ascertain that the nominee holding the 2008 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 notices be provided directly to them.

Redemption notices shall be sent to DTC. If less than all of the 2008 Bonds are being redeemed, DTC's practice is to determine by lot the amount of the interest of each Direct Participant in such issue to be redeemed.

Neither DTC nor Cede & Co. (nor any other DTC nominee) will consent or vote with respect to the 2008 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 2008 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, and Tender Price of, the 2008 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 the payable date in accordance with their respective holdings shown on DTC's records. Payments by Direct or Indirect 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, 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 on, or Tender Price of, the 2008 Bonds 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 will be the responsibility of Direct and Indirect Participants.

A Beneficial Owner shall give notice to elect to have its 2008 Bonds purchased or tendered, if applicable, through its Direct Participant, to the Tender Agent, and shall effect delivery of such 2008 Bonds by causing the Direct Participant to transfer the Direct Participant's interest in the 2008 Bonds, on DTC's records, to the Tender Agent. The requirement for physical delivery of 2008 Bonds in connection with an optional tender or a mandatory purchase will be deemed satisfied when the ownership rights in the 2008 Bonds are transferred by Direct Participants on DTC's records and followed by a book-entry credit of tendered 2008 Bonds to the Tender Agent's DTC account.

DTC may discontinue providing its services as securities depository with respect to the 2008 Bonds at any time by giving notice to the Trustee and NCPA. Under certain circumstances, in the event that a successor depository is not obtained, 2008 Bond certificates are required to be printed and delivered.

NCPA may decide to discontinue use of the system of book-entry transfers for the 2008 Bonds through DTC (or a successor securities depository). In that event, 2008 Bond certificates will be printed and delivered as provided in the Indenture.

NCPA and the Trustee will not have any responsibility or obligation to any DTC Participant, any Beneficial Owner or any other person claiming a beneficial ownership interest in the 2008 Bonds under or through DTC or any DTC Participant, or any other person which is not shown on the registration books of the Trustee as being a Holder with respect to the accuracy of any records maintained by DTC or any DTC Participant; the payment by DTC or any DTC Participant of any amount in respect of the principal of, redemption premium, if any, or interest on the 2008 Bonds; any notice which is permitted or required to be given to Holders; any consent given or other action taken by DTC as a Holder; or any other procedures or obligations of DTC under the book-entry system.

So long as Cede & Co. is the registered owner of the 2008 Bonds, as nominee of DTC, references herein to the Holders or registered owners of the 2008 Bonds will mean Cede & Co., as aforesaid, and will not mean the Beneficial Owners of the 2008 Bonds.

The foregoing description of the procedures and record-keeping with respect to beneficial ownership interest in the 2008 Bonds, payment of principal, premium, if any, Tender Price, interest and other payments on the 2008 Bonds to DTC Participants or Beneficial Owners, confirmation and transfer of beneficial ownership interests in such 2008 Bonds and other related transactions by and between DTC, the DTC Participants and the Beneficial Owners is based solely on information provided by DTC. Accordingly, no representations can be made concerning these matters and neither the DTC Participants nor the Beneficial Owners should rely on the foregoing information with respect to such matters, but should instead confirm the same with DTC or the DTC Participants, as the case may be.

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APPENDIX D

SUMMARY OF CERTAIN PROVISIONS OF THE INDENTURE

The following is a summary of certain provisions of the Indenture. This summary is not to be considered a full statement of the terms of the Indenture and accordingly is qualified by reference thereto and is subject to the full text thereof. Capitalized terms not defined in this summary or elsewhere in the Official Statement have the respective meanings set forth in the Indenture.

Certain Definitions

"Act" means the provisions relating to the joint exercise of powers found in Chapter 5 of Division 7 of Title 1 of the Government Code of California, as amended and supplemented and shall also include the provisions of any other law applicable to NCPA by virtue of being a public entity pursuant to said Chapter 5 of Division 7 of Title 1 including, without limitation, Article 10 and Articles 11 of Chapter 3 of Division 2 of Title 5 of said Government Code, as each thereof may be amended and supplemented.

"Additional Bonds" means all Bonds, whether issued in one or more Series, authenticated and delivered on original issuance pursuant to Section 203 of the Original Indenture and any Bonds thereafter authenticated and delivered in lieu of or in substitution for such Bonds.

"Adjustable Rate Bond" means, as of any date of determination, any Bond not bearing interest from such date to the maturity thereof at a specified, fixed rate; provided, however, that each Adjustable Rate Bond shall also be an Option Bond with a Purchase Date on the Business Day next succeeding the termination of each Adjustment Period for such Bond.

"Adjusted Aggregate Debt Service" means, as of any date of calculation and with respect to any period, the sum of the amounts of Adjusted Debt Service during such period for all Series of Bonds, other than Lender Bonds; provided, however, that in computing such Adjusted Aggregate Debt Service, each Series of Adjustable Rate Bonds shall be deemed to bear the Assumed Interest Rate applicable thereto.

"Adjusted Debt Service" means, with respect to any Series of Bonds, as of any date of calculation and with respect to any period, the Debt Service for such Series of Bonds for such period which would result if the Principal Installment for such Series due on the final maturity date of such Series were adjusted over the period specified pursuant to the next sentence so that the Bonds of such Series would have Substantially Equal Debt Service for each Fiscal Year of such period and that such Principal Installment would be fully paid at the end of such period, assuming timely payment of all principal or Redemption Price, if any, of and interest on the Bonds of such Series in accordance with such adjustments and computing the interest component of Debt Service on the basis of the true interest cost actually incurred on such Series of Bonds (determined by the true, actuarial method of calculation which consists of calculating true interest cost from the actual delivery date of such Series of Bonds as opposed to calculating it from the date of such Series of Bonds). Such adjustment shall be made over a period which shall begin with the final maturity date of such Series and end on such date or a date which shall be specified in the Supplemental Indenture authorizing such Series of Bonds, which date shall be not later than the earlier to occur of (i) 40 years after the date of such Bonds or (ii) the termination date of the Third Phase Agreement. For purposes of computing such true interest cost for any Series of Bonds containing Adjustable Rate Bonds each such Adjustable Rate Bond shall be deemed to bear the Assumed Interest Rate applicable thereto.

"Agreement of Attornment" means the Agreement of Attornment, dated March 22, 1985, by and among NCPA, the Calaveras County Water District and Sierra Constructors, as the same may be amended and supplemented from time to time in accordance with its terms and terms of the Indenture.

"Beneficial Owner" means, with respect to the 2008 Bonds, any person which has or shares the power, directly or indirectly, to make investment decisions concerning ownership of any of the 2008 Bonds (including any person holding 2008 Bonds through nominees, depositories or other intermediaries).

"Business Day" means, as of any time and with respect to the 2008 Series A Bonds, any day other than a Saturday, Sunday or other day on which the New York Stock Exchange is closed or on which banks are authorized or required to be closed in any of the City of [Los Angeles, California], the City of New York, New York, the city where the 2008 Series A Credit Provider is located, the city where the 2008 Series A Liquidity Provider (if any) is located or any other municipalities in which the principal offices of the Trustee or the 2008 Series A Auction Agent (if any) are located.

"Capital Improvements" shall mean all renewals or replacements of or repairs, additions, improvements, modifications or betterments chargeable to the capital account of the Project, which are (i) consistent with Prudent Utility Practice and determined necessary by the Commission to keep the Project in good operating condition or to prevent a loss of revenue therefrom, (ii) required by any governmental agency having jurisdiction over the Project, or (iii) required by the Indenture; provided, however, that Capital Improvements shall not include any additional generating units in addition to the number of generating units presently included in the Project.

"Conversion" means a conversion of any Series of the 2008 Bonds from one Interest Rate Period to another Interest Rate Period.

"Conversion Date" means the effective date of a Conversion of any Series of the 2008 Bonds.

"Debt Service Reserve Requirement" means, as of any date of calculation, and with respect to the Debt Service Reserve Account (which does not secure the 2008 Bonds), an amount equal to the greatest amount of Adjusted Aggregate Debt Service for the Participating Bonds for the then current or any future Fiscal Year and, with respect to a Series Debt Service Reserve Account, the amount, if any, specified as such with respect to such Series Debt Service Reserve Account pursuant to the Indenture.

"Favorable Opinion of Bond Counsel" means an opinion of Bond Counsel acceptable to the Insurer to the effect that the action proposed to be taken is authorized or permitted by the Indenture and will not result in the inclusion of interest on any Bonds in gross income for federal income tax purposes.

"Future Bonds" means all Bonds issued when the Eleventh Supplemental Indenture of Trust became effective, i.e., July 1, 1998.

"Initial Facilities" means those facilities included in or required by the FERC License and all associated facilities, rights, land and interest in land, properties, studies, reports, equipment, transmission facilities and improvements appurtenant thereto and necessary or convenient therewith including without limitation any payments to other parties such as contributions in and of construction in connection with the transmission of the output of the facilities included in the definition of the "Project" under the Power Purchase Contract.

"Interest Payment Date" means, with respect to each Series of Bonds, the dates during each year on which interest on such Series of Bonds is scheduled to be paid as specified in, or determined in accordance with, the Indenture or Supplemental Indenture authorizing such Series of Bonds.

"Investment Securities" means and includes any of the following securities, if and to the extent the same are at the time legal for investment of NCPA's funds:

(i) Direct obligations of, or obligations the principal of and interest on which are unconditionally guaranteed by, the United States of America, including obligations issued or held in book entry form on the books of the Department of the Treasury of the United States and including a receipt, certificate or any other evidence of an ownership interest in the aforementioned obligations, or in specified portions thereof (which may consist of specified portions of interest thereon) and also including advance refunded tax-exempt bonds secured by the aforementioned obligations;

(ii) Bonds, debentures, notes, participation certificates or other evidences of indebtedness issued, or the principal of and interest on which are unconditionally guaranteed, by the Bank for Cooperatives, the Federal Intermediate Credit Bank, the Federal Home Loan Bank System, the Export-

Import Bank of the United States, the Government National Mortgage Association, the Federal National Mortgage Association, the United States Postal Service or any other agency or instrumentality of or corporation wholly owned by the United States of America;

(iii) New Housing Authority Bonds or Project Notes issued by public agencies or municipalities and fully secured as to the payment of both principal and interest by a pledge of annual contributions to be paid by the United States of America or any agency thereof;

(iv) Direct and general obligations, to the payment of which the full faith and credit of the issuer is pledged, of any State of the United States or any political subdivision thereof which at the time of investment is rated by any nationally recognized bond rating agency and assigned by such agency a rating which denotes a security with investment characteristics at least equal to the investment characteristics of a security presently rated by Moody's Investors Service, Inc. or Standard & Poor's Corporation as "A" or better;

(v) Bank time deposits evidenced by certificates of deposit, and banker's acceptances, issued by any bank, trust company or national banking association insured by the Federal Deposit Insurance Corporation; provided either that the aggregate of such bank time deposits and bankers' acceptances issued by any bank, trust company or banking association does not exceed at any one time ten per centum (10%) of the aggregate of the capital stock, surplus and undivided profits of such bank, trust company or banking association and that such capital stock, surplus and undivided profits shall not be less than Twenty-Five Million Dollars ($25,000,000), or that such deposits are fully and continuously secured by a valid and perfected security interest in obligations described in paragraph (i), (ii) or (iii) of this definition; and

(vi) Repurchase agreements with any bank, trust company or national banking association insured by the Federal Deposit Insurance Corporation, or with any government bond dealer recognized as a primary dealer by the Federal Reserve Bank of New York, which agreements are fully and continuously secured by a valid and perfected security interest in obligations described in paragraph (i), (ii) or (iii) of this definition.

"Mandatory Standby Tender" means the mandatory tender for purchase of a Series of the 2008 Bonds pursuant to the related Supplemental Indenture upon receipt by the Trustee of written notice from the Bank that an event with respect to the Reimbursement Agreement or the Letter of Credit relating to such Series has occurred which requires or gives the Bank the option to terminate upon notice.

"Maximum Interest Rate" shall mean, with respect to each Series of 2008 Bonds other than 2008 Bonds held by the Bank under a Reimbursement Agreement, twelve 12% per annum; provided, however, that the Maximum Interest Rate for any 2008 Bond shall not exceed the Maximum Lawful Rate.

"Maximum Lawful Rate" means the maximum rate of interest on the relevant obligation permitted by applicable law.

"Moody's" means Moody's Investors Service, a corporation organized and existing under the laws of the State of Delaware, its successors and their assigns, or, if such corporation shall be dissolved or liquidated or shall no longer perform the functions of a securities rating agency, any other nationally recognized securities rating agency designated by NCPA by notice in writing to the Trustee and acceptable to the Insurer.

"NCPA Operating Expenses" means (i) costs incurred by NCPA pursuant to the Third Phase Agreement, (ii) any other current expenses or obligations required to be paid by NCPA under the provisions of the Project Agreements or by law, all to the extent properly allocable to the Project, or required to be incurred under or in connection with the performance of the Third Phase Agreement, (iii) the fees and expenses of the Fiduciaries, (iv) fees incurred pursuant to any lending or credit facility or agreement, including, without limitation, the Reimbursement Agreements, and (v) all other costs (including overhead) properly allocable to the Project. NCPA Operating Expenses shall not include any costs or expenses for new construction or any allowance for depreciation of the Project.

“NCPA Revenues” means (i) 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, (ii) the proceeds of any insurance, including the proceeds of any self-insurance fund, covering business interruption loss relating to the Project, (iii) any receipts under the Construction Contract or the Agreement of Attornment, other than insurance proceeds required to be deposited in the Construction Fund in accordance with the provisions of the Indenture, and (iv) 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.

“Participating Bonds” means all Bonds Outstanding prior to the Eleventh Supplemental Indenture of Trust becoming effective (July 1, 1998) and all Future Bonds other than Future Bonds which are specified in the Supplemental Indenture authorizing such Future Bonds not to be Participating Bonds in accordance with the provisions of the Indenture.

“Power Purchase Contract” means the Revised Power Purchase Contract, dated as of March 1, 1985, by and between NCPA and CCWD as the same may be amended and supplemented from time to time in accordance with its terms and the terms of the Indenture.

“Principal Office” means, as appropriate, the designated corporate trust office of (1) the Trustee, which as of the date hereof is located at 61 Broadway, New York, New York, Attention: Corporate Trust Department or (2) the Tender Agent, which as of the date hereof, shall be the same as the Trustee, or (3) the Remarketing Agent, the address for the Remarketing Agent designated in the Remarketing Agreement with such Remarketing Agent.

“Project” means the Initial Facilities and all Capital Improvements.

“Project Agreements” means, prior to the respective termination dates thereof, the Indenture, the Third Phase Agreement, the Power Purchase Contract, the Construction Contract, the Agreement of Attornment and any other contract designated a Project Agreement by the Commission of NCPA.

“Prudent Utility Practice” means any of the practices, methods and acts, which, in the exercise of reasonable judgment in the light of the facts (including but not limited to the practices, methods and acts engaged in or approved by a significant portion of the electrical utility industry prior thereto) known at the time the decision was made, would have been expected to accomplish the desired result at the lowest reasonable cost consistent with good business practices, reliability, safety and expedition, taking into account the fact that Prudent Utility Practice is not intended to be limited to the optimum practice, methods or act to the exclusion of all others, but rather to be a spectrum of possible practices, methods or acts which could have been expected to accomplish the desired result at the lowest reasonable cost consistent with reliability, safety and expedition. Prudent Utility Practice includes due regard for manufacturers’ warranties and requirements of governmental agencies of competent jurisdiction and shall apply not only to functional parts of the Project, but also to appropriate structures, landscaping, paining, signs, lighting, other facilities and public relations programs reasonably designed to promote public enjoyment, understanding and acceptance of the Project.

“Purchase Date” means each date on which any 2008 Bonds are to be purchased pursuant to the Indenture.

“Rate Period” means, with respect to a Series of the 2008 Bonds, a Daily Rate Period, a Weekly Rate Period, a Short Term Rate Period, a Long Term Rate Period or an ARS Rate Period.

“Remarketing Agent” means, with respect to a Series of the 2008 Bonds, any Remarketing Agent or successor or additional Remarketing Agent acceptable to the Insurer and appointed in accordance with the Supplemental Indenture with respect to such Series of the 2008 Bonds.

“Securities Depository” means, with respect to a Series of the 2008 Bonds, the securities depository designated in the Supplemental Indenture with respect to such Series and its successors and assigns or if (a) the then incumbent Securities Depository resigns from its functions as depository for such Series of the 2008 Bonds, or (b) NCPA discontinues use of the then incumbent Securities Depository for such Series of the 2008 Bonds pursuant to such Supplemental Indenture, any other securities depository which agrees to follow the procedures required to be followed by a securities depository for such Series of the 2008 Bonds.

"Series Debt Service Reserve Account" means each Account within the Debt Service Fund established with respect to a Series of Future Bonds which are not Participating Bonds, including the 2008 Bonds, pursuant to the Indenture.

"SIFMA Index" means, on any date, a rate determined on the basis of the seven-day high grade market index of tax-exempt variable rate demand obligations, as produced by Municipal Market Data and published or made available by the Securities Industry & Financial Markets Association (formerly the Bond Market Association) ("SIFMA") or any Person acting in cooperation with or under the sponsorship of SIFMA and acceptable to the Trustee and effective from such date.

"Sinking Fund Installment" means with respect to a Series of the 2008 Bonds, the amount required by the Supplemental Indenture with respect to such Series to be paid by NCPA on any single date for the retirement of 2008 Bonds of such Series.

"Substantially Equal Adjusted Aggregate Debt Service" means, with respect to any period of similar Fiscal Years for all Outstanding Bonds, other than Lender Bonds, that the greatest Adjusted Aggregate Debt Service for any Fiscal Year in such period is not in excess of one hundred and twenty-five percent of the Adjusted Aggregate Debt Service for any preceding Fiscal Year in such period.

"Substantially Equal Debt Service" means, with respect to any period of Fiscal Years for any Series of Bonds, other than Lender Bonds, that the greatest Debt Service for such Bonds for any Fiscal Year in such period is not in excess of one hundred and twenty-five percent of the smallest Debt Service for such Bonds for any Fiscal Year in such period.

"Supplemental Indenture" shall mean any indenture supplemental to or amendatory of the Indenture, entered into by NCPA and the Trustee in accordance with the Indenture.

"S&P" means Standard & Poor's Ratings Services, a division of The McGraw-Hill Companies, Inc., a corporation organized and existing under the laws of the State of New York, its successors and their assigns, or, if such corporation shall be dissolved or liquidated or shall no longer perform the functions of a securities rating agency, any other nationally recognized securities rating agency designated by NCPA by notice in writing to the Trustee and acceptable to the Insurer.

"Trust Estate" means (A) subject only to the provisions of the Indenture permitting the application thereof for the purposes and on the terms and conditions set forth in the Indenture, (i) the proceeds of the sale of the Bonds, other than Lender Bonds, (ii) the 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; (B) all right, title and interest of NCPA in, to and under the Third Phase Agreement; (C) all right, title and interest of NCPA in, to and under the Power Purchase Contract; and (D) all right, title and interest of NCPA in, to and under the Construction Contract and the Agreement of Attornment.

"Weekly Interest Rate" means a variable interest rate on a Series of the 2008 Bonds established in accordance with the Supplemental Indenture with respect to such Series.

"Weekly Interest Rate Period" shall mean each period during which Weekly Interest Rates are in effect with respect to a Series of the 2008 Bonds.

Pledge Effected by the Indenture

NCPA has pledged and assigned the Trust Estate to the Trustee for the benefit of the Bondholders.

Nature of Obligation

The Indenture provides that the principal, Redemption Price, if any, and Purchase Price thereof, and interest on the Bonds shall be payable solely from the NCPA Revenues and other funds pledged by NCPA under the Indenture and shall not constitute a charge against the general credit of NCPA. 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, Redemption Price, if any, and Purchase Price of, or interest on the Bonds. NCPA has no taxing power. The Bonds do not constitute a debt, liability or obligation of the State of California or any public agency (other than NCPA) or any member of NCPA or any Project Participant. Neither the members of the Commission of NCPA nor any officer or employee of NCPA shall be individually liable for the Bonds or in respect of any undertakings by NCPA under the Indenture.

Application of NCPA Revenues

NCPA Revenues are pledged by the Indenture to payment of the principal, Redemption Price, if any, and Purchase Price of, and interest on the Bonds, subject to the provisions of the Indenture permitting application for other purposes. The Indenture establishes the following Funds and Accounts for the application of Bond proceeds and NCPA Revenues:

FUNDS	HELD BY
Revenue Fund	NCPA
Operating Reserve Fund	Trustee
Operating Fund	NCPA
Debt Service Fund*	Trustee
Debt Service Account	
Debt Service Reserve Account	
Subordinated Indebtedness Fund	Trustee
Note Fund	Trustee
Reserve and Contingency Fund	NCPA
Renewal and Replacement Account	
Reserve Account	
General Reserve Fund	NCPA
Rate Stabilization Account	
General Account	

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:

(1) To the Operating Reserve Fund, the amount, if any, required so that the balance in said Fund shall equal $100,000 or such greater or lesser amount as shall be recommended by the Consulting Engineer to be on deposit in said Fund .

(2) To the Operating Fund, a sum which, together with any amount in the Operating Fund not set aside as a general reserve for NCPA Operating Expenses or as a reserve for working capital, is equal to the total moneys appropriated for NCPA Operating Expenses in the Annual Budget for the then current month. In addition, if the Supplemental Indenture authorizing a Series of Bonds so provides, amounts from the proceeds of such Bonds may be deposited in the Operating Fund and set aside as a reserve for working capital. Amounts in the Operating Fund shall be paid out from time to time by NCPA for reasonable and

* If provided in a Supplemental Indenture authorizing a Series of Future Bonds which are not Participating Bonds, the Debt Service Fund shall include a Series Debt Service Reserve Account for each such Series of Future Bonds as to which a debt service reserve is to be established.

necessary NCPA Operating Expenses. The Indenture provides for the application of excess amounts in the Operating Fund to make up any deficiencies in certain other funds established under the Indenture with any balance to be deposited in the General Account of the General Reserve Fund.

(3) To the Debt Service Fund (i) for credit to the General Debt Service Subaccount, the amount, if any, required so that the balance in said subaccount, plus the amounts on deposit in all the other subaccounts in the Debt Service Account to the extent available to pay Accrued Aggregate Debt Service, as of the last day of the then current month, shall equal the Accrued Aggregate Debt Service as of the last day of the then current month; (ii) for credit to the Debt Service Reserve Account, the amount, if any, required for such Account to equal the Debt Service Reserve Requirement for the Debt Service Reserve Account as of the last day of the then current month; and (iii) for credit to each Series Debt Service Reserve Account established for Future Bonds, the amount, if any, required for each such Account to equal the applicable Debt Service Reserve Requirement for such Series Debt Service Reserve Account as of the last day of the then current month; provided that the transfers to the Debt Service Reserve Account and each Series Debt Service Reserve Account shall be made to the Debt Service Reserve Account and each Series Debt Service Reserve Account without preference or priority between such transfers made in accordance with clauses (ii) and (iii) of this subsection (a), and in the event of any insufficiency of such moneys ratably based on the amount required to be deposited in each such Account, without any discrimination or preference. The Trustee will apply amounts in the General Debt Service Subaccount in the Debt Service Account to the payment of principal of and interest on the Bonds. In addition, the Trustee may, and if directed by NCPA must, apply certain amounts in the Debt Service Account to the purchase or redemption of Bonds to satisfy sinking fund requirements prior to the due date of any Sinking Fund Installment. The Trustee must pay out of the Debt Service Account the amount required for the redemption of Bonds called for redemption pursuant to sinking fund requirements on any redemption date.

Amounts in the Debt Service Reserve Account are to be applied on the last business day of each month to make up any deficiency in the Debt Service Account with respect to Participating Bonds. Whenever the amount in the Debt Service Reserve Account, together with the amount in the Debt Service Account with respect to Participating Bonds, is sufficient to pay in full all Outstanding Participating Bonds in accordance with their terms, the funds on deposit in the Debt Service Reserve Account will be transferred to the Debt Service Account. So long as the amount in the Debt Service Fund available for such purpose is sufficient to pay all then Outstanding Participating Bonds in full (including principal or applicable sinking fund Redemption Price and interest thereon), no deposits shall be required to be made in the Debt Service Reserve Account. Whenever moneys on deposit in the Debt Service Reserve Account exceed the Debt Service Reserve Requirement with respect to such Account, the excess will be deposited in the Revenue Fund.

In the event of the refunding of Participating Bonds, the Trustee shall, upon the direction of NCPA with the advice of Bond Counsel, withdraw from the Debt Service Reserve Account any and all of the amounts on deposit therein and hold such amounts for the payment of the principal or Redemption Price, if applicable, and interest on such Participating Bonds; provided that such withdrawal shall not be made unless (a) immediately thereafter the Participating Bonds being refunded shall be deemed to have been paid pursuant to the Indenture, and (b) the amount remaining in the Debt Service Reserve Account after such withdrawal shall not be less than the Debt Service Reserve Requirement for the Debt Service Reserve Account.

Amounts in each Series Debt Service Reserve Account are to be applied on the last business day of each month to make up any deficiency in the Debt Service Account with respect to the Future Bonds secured by such Series Debt Service Reserve Account. Whenever the amount in a Series Debt Service Reserve Account, together with the amount in the Debt Service Account with respect to the Future Bonds secured by such Series Debt Service Reserve Account, is sufficient to pay in full all Future Bonds secured by such Series Debt Service Reserve Account then Outstanding in accordance with their terms, the funds on deposit in such Series Debt Service Reserve Account will be transferred to the Debt Service Account and applied to the payment or redemption of the Series of Future Bonds secured by such Series Debt Service Reserve Account. So long as the amount in the Debt Service Fund with respect to a Series of Future Bonds secured by a Series Debt Service Reserve Account is sufficient to pay all such Future Bonds then Outstanding in full (including principal or applicable sinking fund Redemption Price and interest thereon), no deposits shall be required to be made in such Series Debt Service Reserve Account. Whenever moneys on deposit in a Series Debt Service Reserve Account exceed the Debt Service Reserve Requirement with respect to such Account, the excess will be deposited in the Revenue Fund.

In the event of the refunding of Future Bonds secured by a Series Debt Service Reserve Account, the Trustee shall, upon the direction of NCPA with the advice of Bond Counsel, withdraw from the Series Debt Service Reserve Account securing such Future Bonds any and all of the amounts on deposit therein and hold such amounts for the payment of the principal or Redemption Price, if applicable, and interest on such Future Bonds; provided that such withdrawal shall not be made unless immediately thereafter the Future Bonds being refunded shall be deemed to have been paid pursuant to the Indenture,.

(4) To the Subordinated Indebtedness Fund, the amount, if any, required so that the balance in said Fund shall equal all principal and interest on outstanding Subordinated Indebtedness accrued and unpaid and to accrue to the end of the then current calendar month. The Trustee will apply amounts in the Subordinated Indebtedness Fund to the payment of interest and reserves on Subordinated Indebtedness in accordance with the provisions of the resolution, agreement or contract relating to the issuance of such Subordinated Indebtedness. However, if at any time the amounts in the Debt Service Fund are less then the amounts required by the Indenture, and there is not on deposit in the General Reserve Fund or in the Reserve and Contingency Fund or in the Note Fund available moneys sufficient to cure such deficiency, the Trustee will transfer from the Subordinated Indebtedness Fund the amount necessary to make up such deficiency.

(5) To the Note Fund, the amount, if any, required so that the balance in said Fund shall equal all interest on outstanding Notes accrued and unpaid and to accrue to the end of the then current calendar month. The Trustee will apply amounts in the Note Fund to the payment of interest on Notes in accordance with the provisions of the resolution, agreement or contract relating to the issuance of such Notes. However, if at any time the amounts in the Debt Service Fund are less than the amounts required by the Indenture, and there is not on deposit in the General Reserve Fund or in the Reserve and Contingency Fund available moneys sufficient to cure such deficiency, the Trustee will transfer from the Note Fund the amount necessary to make up such deficiency.

(6) To the Reserve and Contingency Fund, for credit to (a) the Renewal and Replacement Account, the amount, if any, provided for deposit therein during the then current month in the current Annual Budget; and (b) the Reserve Account, the amount, if any, required to that the balance in said Account shall equal $3,000,000 or such greater or lesser amount as shall be recommended by the Consulting Engineer to be on deposit in said Account.

Amounts in the Renewal and Replacement Account will be applied to the cost of Capital Improvements. To the extent not provided for in the then current Annual Budget or by reserves in the Operating Fund or from the proceeds of Bonds, amounts in the Reserve Account will be applied to the costs of Capital Improvements to the extent amounts in the Renewal and Replacement Account are not sufficient therefor, and to the payment of extraordinary operating and maintenance costs of the Project and contingencies.

If at any time the amounts in the Debt Service Fund are less than the amounts required by the Indenture, and there are not on deposit in the General Reserve Fund available moneys sufficient to cure such deficiency, then the Trustee will transfer from the Reserve Account and the Renewal and Replacement Account, in that order, the amount necessary to make up such deficiency.

Amounts in the Renewal and Replacement Account or the Reserve Account not required to meet any deficiencies in the Debt Service Fund or for any of the purposes for which such Accounts were established shall be transferred to the Operating Fund to the extent, if any, deemed necessary by NCPA, to make up any deficiencies therein. Any remaining excess shall be deposited into the General Account of the General Reserve Fund.

(7) To the Rate Stabilization Account of the General Reserve Fund, the amount, if any, provided for deposit therein during the then current month in the Annual Budget and, to the General Account of the General Reserve Fund, the balance, if any, in the Revenue Fund. NCPA must transfer from the General Reserve Fund: (a) to the Debt Service Fund amounts necessary to make up any deficiencies in required payments to the Debt Service Fund; and (b) to the Renewal and Replacement Account and the Reserve Account in the Reserve and Contingency Fund the amount necessary to make up any deficiencies in payments to said Accounts.

Amounts in the General Reserve Fund not required to meet any of the deficiencies described above will, upon determination of NCPA, be applied to or set aside for any one or more of the following: (a) transfer to the Revenue Fund; (b) the purchase or redemption of any Bonds, and expenses and reserves in connection therewith; (c) NCPA Operating Expenses or reserves therefor; (d) payments into any separate account or accounts established in the Construction Fund; (e) Capital Improvements or reserves therefor; (f) payment of principal of and interest on Subordinated Indebtedness or purchase or redemption of Subordinated Indebtedness; (g) payment of principal of and interest on Notes; and (h) any other lawful purpose of NCPA related to the Project. Bonds purchased or redeemed with amounts in the General Reserve Fund may be credited to Sinking Fund Installments thereafter to become due (other than the next due).

Deposits from the Revenue Fund into the Debt Service Fund, the Subordinated Indebtedness Fund, the Note Fund, the Reserve and Contingency Fund and the General Reserve Fund are to be made as soon as practicable in each month after the deposit of NCPA Revenues into the Revenue Fund, the Operating Reserve Fund and the Operating Fund have been made for such month, but not later than the last business day of such month.

Certain Requirements of and Conditions to Issuance of Bonds

Bonds shall be authenticated by the Trustee pursuant to the Indenture upon compliance with certain requirements and conditions, including the following:

(a) The Trustee shall have received an Opinion of Bond Counsel to the effect that the Bonds of the Series being issued have been duly and validly authorized, issued and are valid and binding obligations of NCPA and as to certain other matters concerning the Indenture.

(b) The Trustee shall have received the amount, if any, necessary for deposit: (A) in the Debt Service Reserve Account so that the amount in such Account shall equal the Debt Service Reserve Requirement with respect to such Account calculated immediately after the authentication and delivery of each Series of Participating Bonds and (B) in the Series Debt Service Reserve Account, if any, established with respect to each Series of Future Bonds, so that the amount in such Account shall equal the Debt Service Reserve Requirement, if any, with respect to such Account calculated immediately after the authentication and delivery of such Series of Future Bonds;

(c) Except in the case of Lender Bonds and Refunding Bonds, NCPA shall have certified that it is not in default in the performance of its agreements under the Indenture. In the case of Refunding Bonds such certificate may state that upon the application of the proceeds of the Refunding Bonds, NCPA will not be in default in the performance of its agreements under the Indenture.

The Indenture also provides that Principal Installments will be established at the time of issuance for each Series of Bonds so as to comply with the following:

(a) Principal Installments shall commence not later than the later of (A) the first day of the eighth Fiscal Year following the end of the Fiscal Year of authentication and delivery of such Series of Bonds or (B) the first day of the fifth Fiscal Year following the end of the Fiscal Year in which NCPA estimates that the Project will reach its Date of Firm Operation, and shall terminate not later than the date on which the Third Phase Agreement terminates.

(b) Such Principal Installments shall result in either (A) Substantially Equal Debt Service for the Bonds of such Series for the Fiscal Year immediately preceding the due date of the first such Principal Installment to occur subsequent to the Date of Firm Operation of the Project and for each Fiscal Year thereafter to and including the final maturity date of such Series or (B) Substantially Equal Adjusted Aggregate Debt Service for all Outstanding Bonds, including such Series being issued, for the first Fiscal Year in which Principal Installments become due on all Series of Bonds then Outstanding, including such Series being issued, beginning however no earlier than the Fiscal Year immediately preceding the due date of the first Principal Installment to occur subsequent to the Date of Firm Operation of the Project, and for each Fiscal Year thereafter to and including the Fiscal Year immediately preceding the latest maturity of any Series of Bonds Outstanding immediately prior to the issuance of such Series being issued or the Fiscal Year immediately preceding the latest maturity of such Series being issued, whichever is earlier (using in the case of any Series of Bonds sold by competitive bidding a net effective interest rate for the Bonds of such Series as estimated by NCPA); provided that, if the first Principal Installment of any Series of Bonds shall be less than 12 months after the date of issuance thereof, it shall be assumed, for purposes of this calculation, that interest accrued on such Series for the entire 12-month period preceding the first Principal Installment at the same rate as interest accrued for the actual portion of such period during which such Series of Bond was Outstanding.

Additional Bonds

NCPA may issue one or more series of Additional Bonds for the purpose of paying all or a portion of the Cost of Acquisition and Construction of the Project including paying the principal of and interest on any Subordinated Indebtedness or Notes issued for the purpose of paying all or a portion of the Cost of Acquisition and Construction of the Project upon compliance with the conditions to issuance described above.

Refunding Bonds

One or more Series of Refunding Bonds may be issued to refund any Outstanding Bonds of one or more Series or one or more maturities within a Series. Refunding Bonds shall be authenticated and delivered by the Trustee pursuant to the Indenture upon compliance with certain requirements and conditions, including the receipt by the Trustee of either (i) moneys sufficient to pay the applicable Redemption Price of the refunded Bonds to be redeemed plus the amount required to pay principal of refunded Bonds not to be redeemed together with accrued interest on such Bonds to the redemption date or maturity date, as the case may be, or (ii) Investment Securities in such amounts and having such terms as required by the Indenture to pay the principal or Redemption Price, if applicable, and interest due on and before the redemption date or maturity date, as the case may be.

Debt Service Reserves for Future Bonds

Each Series of Future Bonds shall constitute Participating Bonds unless the Supplemental Indenture authorizing such Series of Future Bonds provides that such Series of Future Bonds shall not be Participating Bonds and, if such Series of Future Bonds is to be secured by a Series Debt Service Reserve Account, provides for the establishment of such Series Debt Service Reserve Account and establishes the Debt Service Reserve Requirement for such Account; provided, however, that each Series of Future Bonds shall constitute Participating Bonds unless at or prior to the issuance of such Series of Future Bonds the Trustee shall have received written confirmation from each rating agency then rating the Outstanding Bonds that the issuance of such Series of Future Bonds as other than Participating Bonds, in and of itself, will not result in the withdrawal or reduction in the rating of any Bonds, other than such Series of Future Bonds, to be Outstanding upon the issuance of such Series of Future Bonds.

Notice of Redemption

The Trustee shall give notice of the redemption of any Bonds to be redeemed, which notice shall specify the redemption date and the place or places where amounts due upon redemption will be payable, and, if less than all of the Bonds of any like Series and maturity are to be redeemed, the letters and numbers or other distinguishing marks of such Bonds so to be redeemed, and, in the case of Bonds to be redeemed in part only, such notice shall also specify the respective portions of the principal amount thereof to be redeemed. Such notice shall further state that on such date there shall become due and payable upon each Bond to be redeemed the Redemption Price thereof, or the

Redemption Price of the specified portions of the principal thereof in the case of Bonds to be redeemed in part only, together with interest accrued to the redemption date, and that from and after such date interest thereon shall cease to accrue and be payable.

With respect to the redemption of any Bonds, the Trustee will mail a copy of such notice, not less than thirty (30) days before the redemption date, to the registered owners of any Bonds or portions of Bonds which are to be redeemed, a their last addresses, if any, appearing upon the registry books.

Receipt of such notice shall not be a condition precedent to such redemption of the Bonds and failure to receive any such notice shall not affect the validity of the proceedings for the redemption of Bonds. Upon the request of NCPA, the Trustee shall also give notice of redemption to certain securities depositories and bond services as specified in the Indenture.

Interchangeability and Transfer

Bonds, other than Lender Bonds, upon surrender thereof at the principal corporate trust office of the Bond Registrar with a written instrument of transfer satisfactory to the Bond Registrar, duly executed by the Holder or his duly authorized attorney, may be exchanged for an equal aggregate principal amount of Bonds of the same maturity and of other authorized denominations.

Except for Option Bonds deemed tendered but not actually tendered, Bonds shall be transferable only upon the books of NCPA, which shall be kept for such purposes at the principal corporate trust office of the Bond Registrar, by the Holder thereof in person or by his attorney duly authorized in writing, upon surrender thereof together with a written instrument of transfer satisfactory to the Bond Register duly executed by the Holder or his duly authorized attorney. Upon the transfer of any such Bond, other than a Lender Bond, NCPA shall issue in the name of the transferee a new Bond or Bonds of the same aggregate principal amount and Series and maturity as the surrendered Bond.

In all cases in which the privilege of exchanging Bonds or transferring Bonds is exercised, NCPA shall execute and the Trustee shall authenticate and deliver Bonds in accordance with the provisions of the Indenture. For every such exchange or transfer of Bonds, NCPA or the Bond Registrar may make a charge sufficient to reimburse it for any tax, fee or other governmental charge required to be paid with respect to such exchange or transfer.

Investment of Certain Funds and Accounts

The Indenture provides that certain Funds and Accounts held thereunder may, and in the case of the Debt Service Account and the Debt Service Reserve Account in the Debt Service Fund, the Subordinated Indebtedness Fund, and the Note Fund, subject to the terms of agreements relating to the issuance of the Subordinated Indebtedness and Notes, must, be invested to the fullest extent practicable in Investment Securities; provided that certain of such Funds and Accounts can only be invested in certain types of Investment Securities. The Indenture provides that such investments will mature no later than such times as necessary to provide moneys when reasonably expected to be needed for payments from such Funds and Accounts and provides specific limitations on the terms of investments for moneys in certain Funds and Accounts.

Prior to the completion of the Initial Facilities, interest and investment earnings (net of which (a) represents a return of accrued interest paid in connection with the purchase of any investment or (b) is required to effect the amortization of any premium paid in connection with the purchase of any investment) earned on any moneys or investments in such Funds and Accounts will be paid into the Construction Fund and after such date all such interest shall be paid into the Revenue Fund; except that to the extent provided in the Supplemental Indenture authorizing a Series of Additional Bonds to pay the Cost of Acquisition and Construction of Capital Improvements, all such interest earned on any moneys or investments in the account established in the Construction Fund for such Capital Improvements shall be retained in said account.

The Trustee may deposit moneys in all Funds and Accounts held by it under the Indenture in banks or trust companies organized under the laws of any state of the United States or national banking associations

("Depositaries"). All moneys held under the Indenture by the Trustee or any Depositary must be (1) either (a) continuously and fully insured by the Federal Deposit Insurance Corporation, or (b) continuously and fully secured by lodging with the Trustee or any Federal Reserve Bank, as custodian, as collateral security, such securities as are described in clauses (i) through (iv), inclusive, of the definition of "Investment Security" having a market value (exclusive of accrued interest) not less than the amount of such moneys, or (2) held in such other manner as may then be required by applicable Federal or State of California laws and regulations and applicable state laws and regulations of the state in which the Trustee or such Depositary is located, regarding security for the deposit of trust funds; provided, however, that it shall not be necessary for the Trustee, the Depositaries or any Paying Agent to give security for the deposit of any moneys held in trust by it and set aside for the payment of principal or Redemption Price or Purchase Price of, or interest on, any Bonds or to give security for any moneys which are represented by obligations or certificates of deposit purchased as an investment of such moneys.

In computing the amount in any Fund created under the Indenture, obligations purchased as an investment of moneys therein shall be valued at the amortized costs of such obligations or the market value thereof, whichever is lower, exclusive of accrued interest except that obligations purchased as an investment of moneys in the Debt Service Reserve Account are to be valued at the amortized cost thereof.

Covenants

Encumbrances: Disposition of Properties

NCPA will not issue bonds, notes, debentures or other evidences of indebtedness, other than the Bonds, payable out of or secured by a pledge or assignment of the NCPA Revenues or other moneys, securities or funds held or set aside by NCPA, or the Fiduciaries under the Indenture, nor will it create, or cause to be created, any lien or charge thereon; provided, however, that nothing contained in the Indenture shall prevent NCPA from issuing, if and to the extent permitted by law, (1) evidences of indebtedness (a) payable out of moneys in the Construction Fund as part of the Cost of Acquisition and Construction of the Project or (b) payable out of, or secured by a pledge and assignment of, NCPA Revenues to be derived on and after the discharge of the pledge of NCPA Revenues provided in the Indenture or (2) Subordinated Indebtedness or Notes issued in accordance with the provisions of the Indenture.

NCPA may, however, acquire, construct or finance through the issuance of its bonds, notes or other evidences of indebtedness any facilities which do not constitute a part of the Project for the purposes of the Indenture and may secure such bonds, notes or other evidences of indebtedness by a mortgage of the facilities so financed or by a pledge of, or lien on, the revenues therefrom or any lease or other agreement with respect thereto or any revenues derived from such lease or other agreement; provided that such bonds, notes or other evidences of indebtedness shall not be payable out of or secured by the NCPA Revenues or any Fund or Account held under the Indenture and neither the cost of such facilities nor any expenditure in connection therewith or with the financing thereof shall be payable from the NCPA Revenues or from any such Fund or Account.

NCPA will not sell, lease, mortgage or otherwise dispose of the Project or consent to the sale, lease, mortgage or other disposal of the Project other than in accordance with the Third Phase Agreement.

Rate Covenant

NCPA covenants in the Indenture that so long as any Bonds are Outstanding it will have good right and lawful power to establish charges and cause to be collected amounts with respect to the use of the Project, subject to the terms of the Third Phase Agreement. NCPA covenants in the Indenture that it will at all times establish charges and cause to be collected amounts with respect to the use of the Project, as shall be required to provide NCPA Revenues at least sufficient in each Fiscal Year, together with other available funds, for the payment of all the following:

(a) NCPA Operating Expenses during such Fiscal Year;

(b) An amount equal to the Aggregate Debt Service for such Fiscal Year;

(c) The amount, if any to be paid during such Fiscal Year into the Debt Service Reserve Account and each Series Debt Service Reserve Account in the Debt Service Fund;

(d) The amount, if any, to be paid during such Fiscal Year into the Subordinated Indebtedness Fund;

(e) The amount, if any, to be paid during such Fiscal Year into the Note Fund;

(f) The amount to be paid during such Fiscal Year into the Reserve and Contingency Fund for credit to the Renewal and Replacement Account and the Reserve Account therein; and

(g) All other charges or liens whatsoever payable out of NCPA Revenues during such Fiscal Year.

In estimating Aggregate Debt Service on any Adjustable Rate Bonds for purposes of the preceding paragraph, NCPA shall be entitled to assume that such Adjustable Rate Bonds will bear such interest rate or rates as NCPA shall determine; provided, however, that the interest rate or rates assumed shall not be less than the interest rate borne by such Adjustable Rate Bonds at the time of determination of Aggregate Debt Service.

NCPA will not furnish or supply or cause to be furnished or supplied any use or service of the Project free of charge to any person, firm or corporation, public or private, and NCPA will, consistent with the Project Agreements and upon the direction of the Trustee, enforce the payment of any and all accounts owing to NCPA by reason of the Project by discontinuing such use or service, or by filing suit therefor, as soon as practicable 30 days after any such accounts are due, or by both such discontinuance and by filing suit.

Covenants with Respect to Third Phase Agreement and Project Agreements

NCPA covenants that it will receive and deposit in the Revenue Fund all amounts payable to it under the Third Phase Agreement or otherwise payable to it pursuant to any contract for use of the Project or any part thereof. NCPA will enforce the provisions of the Third Phase Agreement and duly perform its covenants and agreements thereunder, and will not agree to or permit any rescission of or amendment to, or otherwise take any action under or in connection with, the Third Phase Agreement which would reduce the payments required thereunder or which would in any manner materially impair or materially adversely affect the rights or security of Bondholders under the Indenture; provided, however, NCPA is specifically authorized to make certain amendments relating to billing procedures and the sale price of surplus power and energy under the Third Phase Agreement and is also not prohibited from making any other amendments to the Third Phase Agreement.

Subject to the terms of the Indenture, NCPA will enforce or cause to be enforced the provisions of the Project Agreements to which it is a party and duly perform its covenants and agreements thereunder. NCPA will not consent or agree to or permit any rescission of or amendment to or otherwise take any action under or in connection with the Project Agreements which will in any manner materially impair or materially adversely affect the rights of NCPA thereunder or the rights or security of the Bondholders under the Indenture.

Annual Budget

NCPA will file with the Trustee an Annual Budget prepared in accordance with the Third Phase Agreement for each Fiscal Year commencing with the first Power Supply Year. The Annual Budget will set forth the estimated NCPA Revenues and NCPA Operating Expenses of the Project by month for such Fiscal Year and shall include monthly appropriations for the estimated amount to be deposited in each month of such Fiscal Year in the Revenue Fund, including provision for any general reserve for NCPA Operating Expenses and the amount to be deposited in the Renewal and Replacement Account, the Reserve Account in the Reserve and Contingency Fund, the Rate Stabilization Account in the General Reserve Fund and the requirements, if any, for the amounts estimated to be expended from each Fund and Account. NCPA shall review quarterly its estimates set forth in the Annual Budget and in the event such estimates do not substantially correspond with the actual NCPA Revenues, NCPA Operating Expenses or other requirements, NCPA shall adopt an amended Annual Budget for the remainder of such Fiscal

Year. NCPA is also required to adopt such an amended Annual Budget if there are at any time during the year extraordinary receipts or payments of unusual costs. NCPA may also at any time in accordance with the provisions of the Third Phase Agreement, adopt an amended Annual Budget for the remainder of the then current Fiscal Year.

Insurance

NCPA will at all times after commencement of construction of the Project, insure the Project or cause the Project to be insured against such causes customarily insured against and in such amounts as are usually obtained. NCPA will also use its best efforts to maintain or cause to be maintained any additional or other insurance which NCPA deems necessary or advisable to protect its interests and those of the Bondholders. If any useful portion of the Project is damaged or destroyed, NCPA shall, as expeditiously as possible, continuously and diligently enforce its right to cause to be prosecuted the reconstruction or replacement thereof. The proceeds of any insurance, including the proceeds of any self-insurance fund, paid on account of damage or destruction (other than any business interruption loss insurance) shall be held by the Trustee and applied, to the extent necessary, to pay the costs of reconstruction or replacement. The proceeds of any business interruption loss insurance shall be paid into the Revenue Fund unless otherwise required by the Third Phase Agreement.

Accounts and Reports

NCPA will keep or cause to be kept proper and separate books of records and accounts relating to the Project and each Fund and Account established by the Indenture and relating to the costs and charges under the Third Phase Agreement. Such books, together with the Third Phase Agreement and all other books and papers of NCPA relating to the Project, will at all times be subject to the inspection of the Trustee and the Holders of an aggregate of not less than 5% in principal amount of Bonds then Outstanding.

NCPA will file annually with the Trustee an annual report for each Fiscal Year, accompanied by an Accountant's Certificate, relating to the Project, including a statement of assets and liabilities as of the end of such Fiscal Year, a statement of NCPA Revenues and NCPA Operating Expenses and a statement as to the existence of any default under the provisions of the Indenture.

NCPA will notify the Trustee forthwith of any Event of Default or default in the performance by NCPA of a provision of the Indenture. NCPA will file annually with the Trustee a certificate of an Authorized NCPA Representative stating whether, to the best of the signer's knowledge and belief, NCPA has complied with its covenants and obligations in the Indenture and whether there is then existing an Event of Default or other event which would become an Event of Default upon the lapse of time or the giving of notice, or both, and if any such default or Event of Default so exists, specifying the same and the nature and the status thereof.

The reports, statements and other documents required to be furnished to the Trustee pursuant to any provisions of the Indenture will be available for inspection of Bondholders at the office of the Trustee and will be mailed to each Bondholder who files a written request therefor with the Trustee. The Trustee may charge each Bondholder requesting such reports, statements or other documents a reasonable fee to cover reproduction, handling and postage.

Extension of Payment of Bonds

NCPA covenants in the Indenture that it will not extend or assent to the extension of the maturity of any of the Bonds, other than Lender Bonds, or claims for interest. If the maturity of any of the Bonds, other than Lender Bonds, or claims for interest is extended, such Bonds or claims for interest shall not be entitled, in the case of any default under the Indenture, to the benefit of the Indenture or any payment out of NCPA Revenues, Funds or the moneys held by the Trustee or by any Paying Agent or any Depositary, except moneys held in trust for payment of (i) the principal of all Bonds Outstanding the maturity of which has not been extended, (ii) the portion of accrued interest on the Bonds which is not represented by such extended claims for interest and (iii) the accrued interest on the Lender Bonds. Nothing herein shall be deemed to limit the right of NCPA to issue Option Bonds or Refunding Bonds and neither such issuance nor the exercise by the Holder of any Option Bond of any of the rights appertaining to such Option Bond shall be deemed to constitute an extension of maturity of Bonds.

Amendments and Supplemental Indentures

Any of the provisions of the Indenture may be amended by NCPA, with the written consent of the Banks, by a Supplemental Indenture upon the consent of the Holders of at least sixty percent in principal amount in each case of (1) all Bonds then Outstanding and (2) if less than all of the several Series of Outstanding Bonds are affected, the Bonds of each affected Series; excluding, in each case, from such consent, and from the Outstanding Bonds, the Bonds of any specified Series and maturity if such amendment by its terms will not take effect so long as any of such Bonds remain Outstanding. Any such amendment may not permit a change in the terms of any Sinking Fund Installment or the terms of redemption or maturity of the principal of or interest on any Outstanding Bond or make any reduction in principal, Redemption Price, Purchase Price or interest rate without the consent of each affected Holder, or reduce the percentages of consents required for a further amendment.

NCPA may enter into, with the written consent of the Banks (without the consent of any Holders of the Bonds or the Trustee), a Supplemental Indenture to close the Indenture against, or impose additional limitations upon, the issuance of Bonds or other evidences of indebtedness; to authorize Bonds of a Series; to add to the restrictions to be observed by NCPA contained in the Indenture; to add to the covenants of NCPA contained in the Indenture; to confirm any lien or pledge under the Indenture; to authorize the establishment of a fund or funds for self-insurance; to authorize Subordinated Indebtedness or Notes; and to modify any of the provisions of the Indenture in any other respect if (i) no Bonds will be Outstanding at such time or (ii) such modification shall be, and be expressed to be, effective only after all Bonds then Outstanding cease to be Outstanding and all Bonds authenticated and delivered after the adoption of such Supplemental Indenture specifically refer to such Supplemental Indenture in the text of such Bonds. NCPA may enter into, with the written consent of the Banks, a Supplemental Indenture which shall be effective upon the consent of the Trustee (without the consent of any Holders of the Bonds) to cure any ambiguity, supply any omission or correct any defect or inconsistent provision in the Indenture; or to clarify matters or questions arising under the Indenture and not contrary to or inconsistent with the Indenture.

Trustee; Payment Agents

The Trustee may at any time resign on 60 days' notice to NCPA and the Banks. Such resignation will take effect on the date specified in such notice, or, if a successor Trustee has been appointed, such resignation will take effect immediately upon the appointment of such successor. The Trustee may at any time be removed by the Holders of a majority in principal amount of the Bonds then Outstanding. Successor Trustees may be appointed by the Banks and the Holders of a majority in principal amount of Bonds then Outstanding, and failing such an appointment NCPA shall appoint a successor to hold office until the Banks and the Bondholders act. The Trustee and each successor Trustee, if any, must be a bank, trust company, or national banking association doing business and having its principal office in New York, New York or Chicago, Illinois or Los Angeles, California or San Francisco, California and having capital stock and surplus aggregating at least $50,000,000, if there be such an entity willing and able to accept the appointment. The Indenture requires the appointment by NCPA of one or more Paying Agents (which may include the Trustee).

Pursuant to the Indenture, the Trustee, prior to the occurrence of an Event of Default and after the curing of all Events of Default which may have occurred, undertakes to perform only such duties as are specifically set forth in the Indenture. If an Event of Default has occurred and has not been cured, the Trustee shall exercise such of the rights and powers vested in it by the Indenture, and use the same degree of care and skill in their exercise, as a prudent man would exercise or use under the circumstances in the conduct of his own affairs. Subject to the above, neither the Trustee nor any Paying Agent shall be liable in connection with the performance of its duties under the Indenture except for its own negligence, misconduct or default.

NCPA will cause to be paid to the Trustee and any Paying Agent or Depositary reasonable compensation for all services rendered under the Indenture and all reasonable expenses, charges, counsel fees and other disbursements, incurred in the performance of its duties under the Indenture. Each Trustee, Paying Agent or Depositary has a lien on any and all funds held by it under the Indenture securing its rights to compensation except that the proceeds of Drawings under the Letters of Credit or any funds taken into account in calculating the amount drawn under a Letter of Credit are not available for such purpose. NCPA also agrees to indemnify and save each Trustee, Paying Agent or Depositary harmless against any liabilities which it may incur in the exercise and performance of its powers and duties under the Indenture and which are not due to its negligence, misconduct or default.

Defeasance

The pledge of the Trust Estate under the Indenture and all covenants, agreements and other obligations of NCPA to the Bondholders under the Indenture will cease, terminate and become void and be discharged and satisfied whenever all Bonds have been paid in full. Bonds or interest installments will be deemed to have been paid for the purpose of the defeasance referred to above in this paragraph if on the maturity or redemption date thereof Eligible Moneys have been set aside and held in trust by the Paying Agents for such payment. Bonds, other than Lender Bonds, will be deemed to have been so paid prior to the maturity or redemption date thereof whenever the following conditions are met: (1) there have been deposited with the Trustee either Eligible Moneys in an amount which will be sufficient, or Investment Securities purchased with Eligible Moneys the principal of and the interest on which when due, will provide moneys which, together with the Eligible Moneys deposited, will be sufficient, to pay when due principal or Redemption Price, if applicable, and interest due and to become due on such Bonds, (2) in the case of Bonds to be redeemed prior to maturity, NCPA has given to the Trustee irrevocable instructions to mail the notice of redemption therefor, and (3) NCPA has given to the Trustee irrevocable instructions to (i) mail, as soon as practicable, notice to the Holders of such Bonds that the above deposit has been made with the Trustee and that such Bonds are deemed to be paid and stating the maturity or redemption date upon which moneys are to be available to pay principal or Redemption Price, if applicable, on such Bonds and (ii) publish a similar notice.

For purposes of determining whether Adjustable Rate Bonds shall be deemed to have been paid prior to the maturity or redemption date thereof, as the case may be, by the deposit of moneys, or Investment Securities and moneys, if any, in accordance with the preceding paragraph, the interest to come due on such Adjustable Rate Bonds on or prior to the maturity date or redemption date thereof, as the case may be, shall be calculated at the Assumed Interest Rate; provided, however, that if on any date, as a result of such Adjustable Rate Bonds having borne interest at less than the Assumed Interest Rate for any period, the total amount of moneys and Investment Securities on deposit with the Trustee for the payment of interest on such Adjustable Rate Bonds is in excess of the total amount which would have been required to be deposited with the Trustee on such date in respect of such Adjustable Rate Bonds in order to satisfy the preceding paragraph, the Trustee shall, if requested by NCPA, pay the amount of such excess to NCPA free and clear of any trust, lien, pledge or assignment securing the Bonds or otherwise existing under the Indenture.

Option Bonds shall be deemed to have been paid in accordance with the first paragraph of this heading only if there shall have been deposited with the Trustee moneys in an amount which shall be sufficient to pay when due the maximum amount of principal or Redemption Price, if any, and interest on such Bonds which could become payable to the Holders of such Bonds upon the exercise of any options provided to the Holders of such Bonds; provided, however, that if, at the time a deposit is made with the Trustee pursuant to the first paragraph of this heading, the options originally exercisable by the Holder of an Option Bond are no longer exercisable, such Bond shall not be considered an Option Bond for purposes of this paragraph. If any portion of the moneys deposited with the Trustee for the payment of the principal of and Redemption Price, if any, and interest on Option Bonds is not required for such purpose the Trustee shall, if requested by NCPA, pay the amount of such excess to NCPA free and clear of any trust, lien, pledge or assignment securing said Bonds or otherwise existing under the Indenture.

Events of Default and Remedies

Events of Default specified in the Indenture include (i) failure to pay principal or Redemption Price of any Bond when due; (ii) failure to pay any interest installment on any Bond or the unsatisfied balance of any Sinking Fund Installment thereon when due; (iii) failure to pay the Purchase Price of any Option Bond at the time required by the Indenture and such default shall continue for 10 days; (iv) as specified under any Reimbursement Agreement (none of which is in effect); (v) if there is default by NCPA for 120 days after written notice thereof from the Trustee or the Holders of not less than 10% in principal amount of the Bonds then Outstanding in the observance or performance of any other covenants, agreements or conditions contained in the Indenture or in the Bonds; (vi) NCPA shall apply for or consent to the appointment of a receiver or admit in writing its inability to pay its debts generally as they become due; and (vii) a proceeding shall be instituted in any court of competent jurisdiction under any law relating to bankruptcy, insolvency, reorganization or relief of debtors and the same shall result in an entry of an order for relief or continue undismissed or pending unstayed for a period of 60 days. Upon the happening of any such Event of Default described in clause (i), (ii), (iii), (v), (vi) or (vii) above, the Trustee or the Holders of not less than 25% in principal amount of the Bonds then Outstanding may declare the principal of and accrued interest on all Bonds then Outstanding due and payable (subject to a rescission of such declaration upon the curing of such default before the Bonds have matured).

Upon the occurrence of any Event of Default which has not been remedied, NCPA will, if demanded by the Trustee, (1) account, as a trustee of an express trust, for all NCPA Revenues and other moneys, securities and funds pledged or held under the Indenture and (2) cause to be paid over to the Trustee (a) forthwith, all moneys, securities and fund then held by NCPA in any Fund under the Indenture and (b) as received, all NCPA Revenues. The Trustee will apply all moneys, securities, funds and NCPA Revenues received during the continuance of any Event of Default in the following order: (1) to payment of the reasonable and proper charges, expenses and liabilities of the Trustee, the Depositaries and Paying Agents, (2) to the payment of NCPA Operating Expenses, and (3) to the payment of interest on and principal or Redemption Price of the Bonds without preference or priority of interest over principal or Redemption Price or of principal or Redemption Price over interest, unless the principal of all Bonds has not been declared due and payable, in which case first to the payment of interest on and second to the payment of principal or Redemption Price of those Bonds which have become due and payable in order of their due dates, and in the amount available for such payment thereof, ratably, according to the amounts of interest or principal or Redemption Price, respectively, due on such date. In addition, the Trustee will have the right to apply in an appropriate proceeding for appointment of a receiver of the Project.

If an Event of Default has occurred and has not been remedied, the Trustee may, and on request of the Holders of not less than 25% in principal amount of Bonds Outstanding must, proceed to protect and enforce its rights and the rights of the Bondholders under the Indenture forthwith by a suit or suits in equity or at law, whether for the specific performance of any covenant in the Indenture or in aid of the execution of any power granted in the Indenture or any remedy granted under the Act, or for an accounting against NCPA as if NCPA were the trustee of an express trust, or in the enforcement of any other legal or equitable right as the Trustee deems most effectual to enforce any of its rights or to perform any of its duties under the Indenture. The Trustee may, and upon the request of the Holders of a majority in principal amount of the Bonds then Outstanding and upon being furnished with reasonable security and indemnity must, institute and prosecute proper actions to prevent any impairment of the security under the Indenture or to preserve or protect the interests of the Trustee and of the Bondholders.

Upon the occurrence of an Event of Default, NCPA shall give notice to each Project Participant that such Project Participant shall make the payments due by it under the Third Phase Agreement directly to the Trustee.

Except as otherwise provided in the last sentence of this paragraph and except for the rights specifically conferred on the Banks and the Banks' Agent pursuant to the Indenture, no Bondholder will have any right to institute any suit, action or proceeding for the enforcement of any provision of the Indenture or the execution of any trust under the Indenture or for any remedy under the Indenture, unless (1) such Bondholder previously has given the Trustee written notice of an Event of Default, (2) the Holders of at least 25% in principal amount of the Bonds then Outstanding have filed a written request with the Trustee and have afforded the Trustee a reasonable opportunity to exercise its powers and institute such suit, action or proceeding, (3) there has been offered to the Trustee adequate security and indemnity against its costs, expenses and liabilities to be incurred and (4) the Trustee has refused to comply with such request within 60 days after receipt by it of such notice, request and offer of indemnity. The Indenture provides that nothing therein or in the Bonds affects or impairs NCPA's obligation to pay the Bonds and interest thereon due or the right of any Bondholder to enforce such payment of his Bonds.

The Banks' Agent or the Holders of not less than a majority in principal amount of Bonds then Outstanding may direct the time, method and place of conducting any proceeding for any remedy available to the Trustee, or exercising any trust or power conferred upon the Trustee, subject to the Trustee's right to decline to follow such direction upon advice of counsel as to the unlawfulness thereof or upon its good faith determination that such action would involve the Trustee in personal liability or would be unjustly prejudicial to Bondholders not parties to such direction.

Notice of Default

The Trustee shall promptly mail written notice of the occurrence of any Event of Default to each Holder of Bonds at his address, if any, appearing on the registry books of NCPA.

Unclaimed Moneys

Any moneys held by the Trustee, a Paying Agent or Depositary in trust for the payment and discharge of any of the Bonds which remain unclaimed for six years after the date when such Bonds have become due and payable, either at maturity or by call for redemption (unless such moneys were not held at the time of such maturity or call for redemption, and then which remain unclaimed for six years after the date of deposit of such moneys with the Trustee, Paying Agent or Depositary), shall, at the written request of NCPA and after meeting certain publication requirements, be repaid to NCPA, and such Trustee, Paying Agent or Depositary shall thereupon be released and discharged with respect thereto and the Bondholders shall look only to NCPA for the payment of such Bonds.

APPENDIX E

COPY OF FINAL APPROVING OPINION OF BOND COUNSEL
DATED APRIL 2, 2008

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ORRICK

ORRICK, HERRINGTON & SUTCLIFFE LLP
777 SOUTH FIGUEROA STREET
SUITE 3200
LOS ANGELES, CA 90017-5855
tel 213-629-2020
fax 213-612-2499
WWW.ORRICK.COM

April 2, 2008

Commission
Northern California Power Agency
180 Cirby Way
Roseville, California 95678

Northern California Power Agency
Hydroelectric Project Number One Revenue Bonds,
2008 Refunding Series A and 2008 Taxable Refunding Series B
(Final Opinion)

Ladies and Gentlemen:

We have acted as bond counsel in connection with the issuance by the Northern California Power Agency (the "Agency") of $85,160,000 aggregate principal amount of Hydroelectric Project Number One Revenue Bonds, 2008 Refunding Series A (the "2008 Series A Bonds"), and $3,165,000 aggregate principal amount of Hydroelectric Project Number One Revenue Bonds, 2008 Taxable Refunding Series B (the "2008 Series B Bonds" and, together with the 2008 Series A Bonds, the "2008 Bonds"). The 2008 Bonds have been issued pursuant to the provisions of Chapter 5 of Division 7 of Title 1 the Government Code of the State of California and Articles 10 and 11 of Chapter 3 of Division 2 of Title 5 of the Government Code of the State of California and the Indenture of Trust, dated as of March 1, 1985 by and between the Agency and U.S. Bank Trust National Association, as successor trustee, as amended and supplemented (the "Indenture"). Capitalized terms not otherwise defined herein shall have the meanings ascribed thereto in the Indenture.

The 2008 Bonds have been issued to provide a portion of the funds necessary to refund a portion of the Outstanding principal amount of the Agency's Hydroelectric Project Number One Revenue Bonds, 1998 Refunding Series A.

In such connection, we have reviewed the Indenture, the Hydroelectric Project Member Agreement, the Tax Certificate of the Agency relating to the 2008 Bonds (the "Tax Certificate"), certificates of the Agency, the Trustee, the Project Participants and others, opinions of counsel to the Agency and to each Project Participant, and such other documents, opinions and matters to the extent we deemed necessary to render the opinions set forth herein.

The opinions expressed herein are based on an analysis of existing laws, regulations, rulings and court decisions and cover certain matters not directly addressed by such authorities.

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Such opinions may be affected by actions taken or omitted or events occurring after the date hereof. We have not undertaken to determine, or to inform any person, whether any such actions are taken or omitted or events do occur or any other matters come to our attention after the date hereof. Accordingly, this opinion speaks only as of its date and is not intended to, and may not, be relied upon in connection with any such actions, events or matters. Our engagement with respect to the 2008 Bonds has concluded with their issuance and we disclaim any obligation to update this letter. We have assumed the genuineness of all documents and signatures presented to us (whether as originals or 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 assumed without undertaking to verify 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, the Hydroelectric Project Member Agreement and the Tax Certificate, including (without limitation) covenants and agreements compliance which is necessary to assure that future actions, omissions or events will not cause interest on the 2008 Series A Bonds to be included in gross income for federal income tax purposes. We call attention to the fact that the rights and obligations under the 2008 Bonds, the Indenture, the Hydroelectric Project Member Agreement and the Tax Certificate, and their enforceability, may be subject to bankruptcy, insolvency, reorganization, arrangement, fraudulent conveyance, moratorium and other laws relating to or affecting creditors' rights, to the application of equitable principles, to the exercise of judicial discretion in appropriate cases, and to the limitations on legal remedies against public entities in the State of California. We express no opinion with respect to any indemnification, contribution, penalty, choice of law, choice of forum, choice of venue, waiver or severability provisions contained in the foregoing documents, nor do we express any opinion with respect to the state or quality of title to or interest in any of the assets described in or as subject to the lien of the Indenture or the accuracy or sufficiency of the description contained therein of, or the remedies available to enforce liens on, any such assets. Finally, we undertake no responsibility for the accuracy, completeness or fairness of the Official Statement or other offering material related to the 2008 Bonds and express no opinion with respect thereto.

Based on and subject to the foregoing, and in reliance thereon, as of the date hereof, we are of the following opinions:

1. The 2008 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 2008 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 2008 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 2008 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 any public agency 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 2008 Bonds. The 2008 Bonds do not constitute a debt, liability or obligation of the State of California or any public agency thereof (other than the Agency), any member of the Agency or any Project Participant.

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.

5. Interest on the 2008 Series A Bonds is excluded from gross income for federal income tax purposes under section 103 of the Internal Revenue Code of 1986 and is exempt from State of California personal income taxes. Interest on the 2008 Series A Bonds is not a specific preference item for purposes of the federal individual or corporate alternative minimum taxes, although we observe that it is included in adjusted current earnings when calculating federal corporate alternative minimum taxable income. We express no opinion regarding other tax consequences related to the ownership or disposition of, or the accrual or receipt of interest on, the 2008 Series A Bonds.

ORRICK

6. Interest on the 2008 Series B Bonds is exempt from State of California personal income taxes. We express no opinion regarding other tax consequences related to the ownership or disposition of, or the accrual or receipt of interest on, the 2008 Series B Bonds.

Faithfully yours,

ORRICK, HERRINGTON & SUTCLIFFE LLP

per

APPENDIX F

PROPOSED FORM OF OPINION OF BOND COUNSEL IN CONNECTION WITH THE DELIVERY OF THE LETTERS OF CREDIT

September 10, 2014

Northern California Power Agency
Roseville, California

Alternate 2008 Series A Credit Facility
and Alternate 2008 Series A Liquidity Facility
Relating to
Northern California Power Agency
Hydroelectric Project Number One Revenue Bonds
2008 Refunding Series A

Ladies and Gentlemen:

We have acted as Bond Counsel to the Northern California Power Agency (the "Agency") in connection with the delivery of an irrevocable direct pay letter of credit, dated September 10, 2014 (the "Letter of Credit"), issued by Bank of Montreal, acting through its Chicago Branch (the "Bank"), pursuant to a Letter of Credit Reimbursement Agreement, dated as of September 1, 2014 (the "Reimbursement Agreement"), between the Agency and the Bank to secure the Northern California Power Agency Hydroelectric Project Number One Revenue Bonds, 2008 Refunding Series A (the "2008 Series A Bonds"). The 2008 Series A Bonds were issued pursuant to an Indenture of Trust, dated as of March 1, 1985 by and between the Agency and U.S. Bank National Association, as successor trustee (as amended and supplemented, the "Indenture"). Capitalized terms not otherwise defined herein shall have the meanings ascribed thereto in the Indenture.

The Letter of Credit is being delivered to the Trustee as an Alternate 2008 Series A Credit Facility and an Alternate 2008 Series A Liquidity Facility to serve as the 2008 Series A Credit Facility and 2008 Series A Liquidity Facility in substitution for the irrevocable, direct pay letter of credit issued by Citibank, N.A. (such delivery of the Letter of Credit as an Alternate 2008 Series A Credit Facility and an Alternate 2008 Series A Liquidity Facility to serve as the 2008 Series A Credit Facility and 2008 Series A Liquidity Facility being referred to herein as the "Substitution").

In connection with the Substitution, as bond counsel to the Agency, we have reviewed the Letter of Credit, the Reimbursement Agreement, certificates of the Agency and others, and such other documents, opinions and matters to the extent we deemed necessary to render the opinion set forth herein.

The opinion expressed herein is based on an analysis of existing laws, regulations, rulings and court decisions and covers certain matters not directly addressed by such authorities. Such opinion may be affected by actions taken or omitted or events occurring after the date hereof. We have not undertaken to determine, or to inform any person, whether any such actions are taken or omitted or events do occur or any other matters come to our attention after the date hereof, and we disclaim any obligation to update this letter. 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 party other than the Agency. We have assumed, without undertaking to verify, 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, the Reimbursement Agreement and the Tax Certificate (including any supplements or amendments thereto), including (without limitation) covenants and agreements compliance with which is necessary to assure that actions, omissions or events on and after the date of issuance of the 2008 Series A Bonds have not caused and will not cause interest on the 2008 Series A Bonds to be included in gross income for federal income tax purposes. We have not undertaken to determine compliance with any of such covenants and agreements or any other requirements of law, and, except as expressly set forth below, we have not otherwise reviewed any actions, omissions or events occurring after the date of issuance of the 2008 Series A Bonds or the exclusion of interest on the 2008 Series A Bonds from gross income for federal income tax purposes. Accordingly, no opinion is expressed herein as to whether interest on the 2008 Series A Bonds is excludable from gross income for federal income tax purposes or as to any other tax consequences related to the ownership or disposition of, or the amount, accrual or receipt of interest on, the 2008 Series A Bonds. Nothing in this letter should imply that we have considered or in any manner reaffirm any of the matters covered in any prior opinion we rendered with respect to the 2008 Series A Bonds. Finally, we undertake no responsibility for the accuracy, completeness or fairness of the Remarketing Memorandum, dated August 29, 2014, or other offering material relating to the 2008 Series A Bonds and express no opinion with respect thereto.

Based on and subject to the foregoing, and in reliance thereon, as of the date hereof, we are of the opinion that the delivery of the Letter of Credit to the Trustee as the 2008 Series A Credit Facility and 2008 Series A Liquidity Facility will not, in and of itself, adversely affect any exclusion of interest on the 2008 Series A Bonds from gross income for purposes of federal income taxation.

This letter is furnished by us as bond counsel to the Agency solely in connection with the Substitution and is not to be used or relied upon by the Agency for any other purpose or by any other person. This letter is not intended to, and may not, be relied upon by owners of 2008 Series A Bonds or any other party to whom it is not specifically addressed.

Very truly yours,

APPENDIX G

FORMS OF THE LETTERS OF CREDIT

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[FORM OF 2008 SERIES A LETTER OF CREDIT]

BANK OF MONTREAL,
ACTING THROUGH ITS CHICAGO BRANCH

IRREVOCABLE LETTER OF CREDIT

[_______], 2014

September __, 2014
**US $__________
No. **[________]**

U.S. Bank National Association
____
____
Attention: _________________

Re: $85,160,000
Northern California Power Agency
Hydroelectric Project Number One Revenue Bonds
2008 Refunding Series A

Ladies and Gentlemen:

At the request and for the account of Northern California Power Agency (*"NCPA"*), a joint exercise of powers agency organized and existing under the laws of the State of California pursuant to the Letter of Credit Reimbursement Agreement dated as of **[______]**, 2014, between Bank of Montreal, acting through its Chicago Branch (the *"Bank"*) and NCPA (as amended, supplemented or restated from time to time pursuant to its terms, the *"Reimbursement Agreement"*) between us and NCPA, we hereby establish this Irrevocable Letter of Credit No. **[_________]** (the *"Letter of Credit"*) in your favor as Trustee (the *"Trustee"*) and as Tender Agent (the *"Tender Agent"*) under the Indenture of Trust, dated as of March 1, 1985 (the *"Original Indenture"*), as supplemented by that Sixteenth Supplemental Indenture of Trust dated as of April 1, 2008 (the *"Supplemental Indenture,"* and together with the Original Indenture and as amended or supplemented from time to time pursuant to its terms, the *"Indenture"*), by and between you, in your capacity as Trustee and as Tender Agent, for the benefit of the holders of NCPA's bonds issued under the Indenture and referenced above (the *"Bonds"*) in accordance with the following terms and conditions. Capitalized terms used herein shall have the meanings assigned to such terms in the Reimbursement Agreement.

1. *Termination.* This Letter of Credit automatically shall terminate on the Termination Date. As used herein, *"Termination Date"* shall (except as otherwise specified below in this Paragraph 1) mean 5:00 p.m., New York City time on the earliest of:

(a) September 9, 2019 (the *"Expiration Date"*); provided that, if on or before such date, or such later date to which the term of this Letter of Credit is extended, as provided herein, we provide you with a written notice in the form of Exhibit K hereto that this Letter of Credit shall be extended, the term of this Letter of Credit shall be extended to the date provided in such notice (any date to which the Expiration Date has been extended as herein provided may be extended in a like manner);

(b) the date on which we receive notice from the Trustee in the form of Exhibit E hereto stating that the principal amount of and interest on all of the Bonds has been paid in full or deemed paid in full in accordance with the provisions of Section 1301 of the Original Indenture and Section 607 of the Supplemental Indenture;

(c) the date on which we receive notice from the Trustee in the form of Exhibit F hereto stating that all of the Bonds have been converted to a rate other than a Covered Rate under Section 204 of the Supplemental Indenture but only after we have honored all Drawings made in strict conformity with the terms of this Letter of Credit on or before such date;

(d) the date on which we receive notice from the Trustee in the form of Exhibit G hereto stating that an Alternate Credit Facility has become effective under Sections 406 and 410 of the Supplemental Indenture in substitution for this Letter of Credit but only after we have honored all Drawings made in strict conformity with the terms of this Letter of Credit on or before such date; or

(e) the date which is six (6) Business Days after you have received a Termination Event of Default Notice in the form of Exhibit I hereto.

In the event the Expiration Date shall not be a Business Day, then this Letter of Credit shall expire on the next succeeding Business Day.

2. *Stated Amount.* The maximum aggregate amount available under this Letter of Credit shall be $90,815,558, which amount, as from time to time reduced and reinstated as provided in Paragraphs 3 and 4, is hereinafter referred to as the *"Stated Amount."* Of the Stated Amount, up to $85,160,000 is available for the payment of the unpaid principal of, or the portion of the Purchase Price corresponding to principal of, the Bonds (the *"Principal Portion"*) and up to $5,655,558 is available for the payment of the unpaid interest accrued on, or the portion of the Purchase Price corresponding to interest accrued on, the Bonds (the *"Interest Portion"*) for the immediately preceding two hundred two (202) days, calculated at a rate of twelve percent (12%) per annum based on a year of 365 days.

3. *Reductions in the Stated Amount.* The Stated Amount shall be reduced automatically from time to time as follows:

(a) Upon our honoring of a Drawing hereunder, the Stated Amount shall be reduced by an amount equal to the amount of such Drawing.

(b) Upon our receipt of your certificate in the form of Exhibit D hereto appropriately completed, the Stated Amount, the Principal Portion and the Interest Portion shall be permanently reduced by an amount equal to the amount specified in such certificate.

Upon such a reduction, we may require you to return the original of this Letter of Credit and to accept in substitution hereof a substitute Letter of Credit for a Stated Amount reflecting such reduction, but otherwise identical in form and substance to this Letter of Credit.

4. *Reinstatement.* (a) Reductions under Paragraph 3(a) with respect to any Interest Drawing shall be reinstated on the sixth (6th) Business Day following such Drawing unless (i) you receive from us before the close of business on the fifth (5th) Business Day after such Drawing was honored by us a notice in the form of Exhibit I hereto stating that an Event of Default has occurred under the Reimbursement Agreement and, as a result thereof, the amount of such Interest Drawing will not be reinstated and directing you to cause a mandatory tender for purchase of all Bonds pursuant to the Indenture or (ii) such sixth Business Day falls after the Expiration Date.

(b) Reductions under Paragraph 3(a) with respect to any Purchase Drawing to pay the Purchase Price of Eligible Bonds tendered or deemed to have been tendered pursuant to Section 404(a) or 404(b) of the Supplemental Indenture (an *"Optional Tender"*) shall be reinstated upon the Bank's receipt of a certificate in the form of Exhibit J hereto and receipt of the amounts described in such certificate. Any such reinstatement shall be in an amount equal to the amount indicated in such certificate.

(c) Reductions under Paragraph 3(b) shall not be subject to reinstatement. Reductions under Paragraph 3(a) with respect to any Drawing to pay the (i) principal of the Bonds or (ii) Purchase Price of Bonds tendered or deemed to have been tendered pursuant to Sections 404(d) or 404(e) of the Supplemental Indenture (each, a *"Mandatory Tender"* and together with any Optional Tender, a *"Tender"*) shall not be subject to reinstatement.

5. *Documents To Be Presented.* Funds under this Letter of Credit are available to you, against:

(a) in the case of a demand for payment of scheduled and unpaid interest accrued on the Bonds, a certificate signed by you in the form of Exhibit A hereto appropriately completed (an *"Interest Drawing"*);

(b) in the case of a demand for payment of the unpaid principal of the Bonds, a certificate signed by you in the form of Exhibit B hereto appropriately completed (a *"Principal Drawing"*); and

(c) in the case of a demand for payment of the Purchase Price of Bonds pursuant to a Tender, a certificate signed by you in the form of Exhibit C hereto appropriately completed (a *"Purchase Drawing"*).

6. *Method and Notice of Presentment.* The certificates referenced in Paragraph 5 (each a *"Drawing"*), and any other certificate or notice required or permitted to be provided to us hereunder, shall be in writing and dated the date of presentation and, in the case of each Drawing and the certificates in the form of Exhibits E, F, G and J hereto, respectively, shall be delivered to us by facsimile; and, in all other cases, shall be delivered to us at the address stated in paragraph 14 hereof, in person, by first class registered or certified mail or by an express delivery service. A Drawing (and any certificate in the form of Exhibits E, F, G and J hereto) shall be presented by facsimile on or after the date of this Letter of Credit during our business hours on a Business Day on or prior to the Termination Date at our office at Bank of Montreal, acting through its Chicago Branch, at facsimile number ________________, or at any other number or numbers which may be designated by the Bank by written notice delivered to you. The certifications the Trustee and Tender Agent is required to submit to the Bank should be on the Trustee's and Tender Agent's letterhead and purportedly signed by an authorized officer of the Trustee and Tender Agent.

7. *Time and Method for Payment.* Payments made hereunder shall be made in accordance with the instructions specified by the Tender Agent in the drawing certificate relating to a particular Drawing hereunder. (a) If a Drawing is made by you in strict conformity with the terms and conditions of this Letter of Credit, we will honor the Drawing (i) in the case of a Principal Drawing or an Interest Drawing, if such Drawing is received by us prior to 3:00 p.m. on a Business Day, not later than 2:00 p.m. on the next succeeding Business Day or such later date as you may specify in such Drawing; and (ii) in the case of a Purchase Drawing, if such Drawing is received by us prior to 11:30 a.m. on a Business Day, not later than 2:30 p.m. on such Business Day or such later date as you may specify in such Drawing. If a Drawing is received by us on a day which is not a Business Day or is received after 3:00 p.m. (in the case of a Principal Drawing or an Interest Drawing) or after 11:30 a.m. (in the case of a Purchase Drawing) on a Business Day, such Drawing shall be deemed to have been received by us on the next Business Day, and we will honor such Drawing (in the case of a Principal Drawing or an Interest Drawing) by 2:00 p.m. on the Business Day next succeeding the Business Day on which the Drawing is deemed to have been received by us or (in the case of a Purchase Drawing) by 2:30 p.m. on the Business Day on which the Drawing is deemed to have been received by us; provided in any case that the Business Day on which a Drawing is requested to be honored by us in accordance with the terms of this Paragraph 7 is on or prior to the Termination Date. All times referenced herein are as of New York City time.

(b) Unless otherwise agreed, payment under this Letter of Credit shall be made by Fedwire in immediately available funds to **[________________]**. For the purposes of determining compliance with the times for payment specified in subparagraph (a) above, payment shall be deemed to have been made by us when we have delivered appropriate wire transfer instructions to an appropriate Federal Reserve Bank.

(c) All payments made by the Bank under this Letter of Credit shall be made with the Bank's own funds and not with the funds of any other Person.

8. *Other Documents in the Case of Payment, Conversion or Substitution.* You agree to provide to us a duly completed certificate (a) in the form of Exhibit E hereto upon the payment

or deemed payment of all principal of and interest on the Bonds in full as described in Paragraph 1(b), (b) in the form of Exhibit F hereto upon the Conversion of all of the Bonds to a rate other than a Covered Rate as set forth in Paragraph 1(c), and (c) in the form of Exhibit G hereto upon the delivery of an Alternate Credit Facility in substitution for this Letter of Credit as set forth in Paragraph 1(d); and you agree that each such certificate shall be provided upon the occurrence of such payment, conversion or delivery.

9. *Transferability.* This Letter of Credit is transferable in its entirety, but not in part, to any transferee who has succeeded you as Trustee and as Tender Agent under the Indenture and may be successively transferred; *provided* that under no circumstances shall this Letter of Credit be transferred to any person or entity with which U.S. persons or entities are prohibited from conducting business under U.S. Foreign Assets Control Regulations or any other applicable U.S. laws and regulations or to any person or entity with which the Bank is prohibited from doing business pursuant to the Bank's policies. Transfer of this Letter of Credit to such transferee shall be effected by your presentation to us of the original of this Letter of Credit, including all amendments, if any, hereto accompanied by a certificate designating the Trustee's and Tender Agent's successor in the form of Exhibit H hereto, with the signature of the appropriate officer signing on the Trustee's and Tender Agent's behalf verified by an officer of the Trustee's and Tender Agent's bank.

10. *Governing Law and Practices.* This Letter of Credit is governed by, and construed in accordance with, the International Standby Practices (1998), International Chamber of Commerce, Publication No. 590 (the *"ISP98"*). As to matters not governed by ISP98, this Letter of Credit shall be governed by and construed in accordance with the laws of the State of New York, including, without limitation, the Uniform Commercial Code as in effect in the State of New York, without regard to conflict of laws.

11. *Irrevocability.* This Letter of Credit shall be irrevocable.

12. *No Negotiation.* A Drawing under this Letter of Credit shall be presented directly to us by you or by any transferee who has succeeded you as Trustee and as Tender Agent under the Indenture and shall not be negotiated to or by any third party.

13. *Excluded Bonds, Excluded Drawings.* Notwithstanding any other provision of this Letter of Credit, no Drawing under this Letter of Credit may be made (a) by presentation of a Drawing prior to the date hereof or after the Termination Date, (b) requesting that such Drawing be paid after the Termination Date, (c) with respect to any Bank Bond, any Bond bearing interest at a rate other than a Covered Rate, or any Bond registered in the name of, or to the best of your knowledge held for the account or benefit of, NCPA, or any Affiliate of NCPA, or a Person who is a guarantor of any of the obligations of NCPA with respect to the Bonds (each an *"Excluded Bond"* and each Bond that is not an Excluded Bond, an *"Eligible Bond"*), or (d) for the payment of any redemption or prepayment premium (any Drawing described in any of (a) through (d) being an *"Excluded Drawing"*). For the purposes of this Letter of Credit, "*Affiliate*" means, with respect to any Person, any other Person directly or indirectly controlling, controlled by or under common control with such Person (and *"control"* (including *"controlled by"* and *"under common control with"*) means the power, directly or indirectly, to direct or cause the direction of

the management and policies of such Person, whether through the ownership of voting securities or by contract or otherwise).

14. *Address for Communications.* Communications with respect to this Letter of Credit (other than the presentation of Drawings) shall be in writing and shall be addressed to us at Bank of Montreal, ________________, specifically referring thereon to our Irrevocable Letter of Credit No. **[_______]**. At the time any such communications are sent, copies of such communications shall also be sent by facsimile to us at Bank of Montreal, acting through its Chicago Branch, at facsimile number ________________; *provided, however,* that the failure to send such copies shall not affect our obligations hereunder. For telephone assistance, please contact ________________, and have the Letter of Credit number available. Communications with respect to the Trustee or Tender Agent shall either be sent by first class registered or certified mail or express courier service, properly addressed and prepaid, or physically delivered to the address set forth on the first page of this Letter of Credit.

15. *Complete Agreement.* This Letter of Credit, including Exhibits A through K hereto, sets forth in full the terms of our undertaking. Reference in this Letter of Credit to other documents or instruments is for identification purposes only and any such reference (including, without limitation, the use herein of terms defined in the Reimbursement Agreement) shall not modify, amend, amplify, limit or otherwise affect the terms of our undertaking or cause such documents or instruments to be deemed incorporated herein.

[REMAINDER OF PAGE INTENTIONALLY LEFT BLANK]

We hereby agree with you to honor your Drawings presented in strict compliance with the terms and conditions of this Letter of Credit.

Very truly yours,

BANK OF MONTREAL, acting through its Chicago Branch, as Bank

By ____________________________________
Name ________________________________
Title _________________________________

EXHIBIT A

CERTIFICATE FOR INTEREST DRAWING

$85,160,000
NORTHERN CALIFORNIA POWER AGENCY
HYDROELECTRIC PROJECT NUMBER ONE REVENUE BONDS
2008 REFUNDING SERIES A

IRREVOCABLE LETTER OF CREDIT NO. [________]

The undersigned, a duly authorized officer of U.S. Bank National Association (the *"Trustee"*), hereby certifies to the Bank of Montreal, acting through its Chicago Branch (the *"Bank"*), with reference to Irrevocable Letter of Credit No. **[________]** (the *"Letter of Credit"*; any capitalized term used herein and not defined shall have its respective meaning as set forth in the Letter of Credit) issued by the Bank in favor of the Trustee, that:

1. The Trustee is the Trustee under the Indenture and is making this demand for payment of interest accrued on the Bonds in accordance with the Indenture, which interest is payable on ______________ (the *"Payment Date"*).

2. The amount of interest on the Bonds that is payable on the Payment Date equals $______________.

3. Demand is hereby made under the Letter of Credit for $______________, which amount does not exceed (i) the amount in paragraph (2) or (ii) the Interest Portion of the Stated Amount.

4. The amount demanded hereunder does not include any amount payable with respect to an Excluded Bond or an Excluded Drawing as described in Paragraph 13 of the Letter of Credit.

5. The proceeds hereof shall be deposited in the 2008 Series A Credit Facility Fund (as defined in the Supplemental Indenture) and shall be applied solely to the payment of unpaid interest on the Bonds in accordance with Section 305(b) of the Supplemental Indenture.

(a) Payment of this demand for payment is requested on or before 2:00 p.m., on the later of (i) the Payment Date (or if the Payment Date is not a Business Day, the next succeeding Business Day) and (ii) the Business Day next succeeding the Business Day on which this Certificate is received or deemed to have been received by the Bank in accordance with Paragraph 7(a) of the Letter of Credit.

(b) Payment of this demand for payment shall be made in accordance with the payment instructions provided in Paragraph 7(b) of the Letter of Credit.

6. The amount set forth in paragraph 3 of this Certificate does not exceed the amount available on the date hereof to be drawn under the Letter of Credit in respect of payment of interest accrued on the Bonds on or prior to their stated maturity date or to the redemption or prepayment date, as the case may be, and the amount set forth in paragraph 3 of this Certificate was computed in accordance with the terms and conditions of the Bonds, the Indenture and the Letter of Credit.

7. Drawn under Bank of Montreal, acting through its Chicago Branch, Irrevocable Letter of Credit No. **[________]**: Pay the amount of $[_____________] in interest with respect to the Bonds as certified above.

IN WITNESS WHEREOF, the Trustee has executed and delivered this Certificate as of the ___ day of ___________, 20__.

U.S. BANK NATIONAL ASSOCIATION, as Trustee

By ____________________________________
Name ________________________________
Title _________________________________

EXHIBIT B

CERTIFICATE FOR PRINCIPAL DRAWING

$85,160,000
NORTHERN CALIFORNIA POWER AGENCY
HYDROELECTRIC PROJECT NUMBER ONE REVENUE BONDS
2008 REFUNDING SERIES A

IRREVOCABLE LETTER OF CREDIT NO. [________]

The undersigned, a duly authorized officer of U.S. Bank National Association (the *"Trustee"*), hereby certifies to the Bank of Montreal, acting through its Chicago Branch (the *"Bank"*), with reference to Irrevocable Letter of Credit No. **[________]** (the *"Letter of Credit"*; any capitalized term used herein and not defined shall have its respective meaning as set forth in the Letter of Credit) issued by the Bank in favor of the Trustee, that:

1. The Trustee is the Trustee under the Indenture and is making this demand for payment of principal of the Bonds in accordance with the Indenture, which principal is payable on ________________ (the *"Payment Date"*), by reason of: **[check (a), (b) or (c) as applicable]**

______ (a) scheduled maturity;

______ (b) redemption in whole or in part;

______ (c) the occurrence of an Event of Default (as defined in the Indenture) under the Indenture and declaration of acceleration thereunder.

2. The amount of principal of the Bonds that is payable on the Payment Date equals $_____________.

3. Demand is hereby made under the Letter of Credit for $_____________, which amount does not exceed (i) the amount in paragraph (2) or (ii) the Principal Portion of the Stated Amount.

4. The amount demanded hereunder does not include any amount payable with respect to an Excluded Bond or an Excluded Drawing as described in Paragraph 13 of the Letter of Credit.

5. The proceeds hereof shall be deposited in the 2008 Series A Credit Facility Fund (as defined in the Supplemental Indenture) and shall be applied solely to the payment of the principal of Bonds in accordance with Section 305(b) of the Supplemental Indenture.

6. (a) Payment of this demand for payment is requested on or before 2:00 p.m., on the later of (i) the Payment Date (or if the Payment Date is not a Business Day, the next succeeding

Business Day) and (ii) the Business Day next succeeding the Business Day on which this Certificate is received or deemed to have been received by the Bank in accordance with Paragraph 7(a) of the Letter of Credit.

(b) Payment of this demand for payment shall be made in accordance with the payment instructions provided in Paragraph 7(b) of the Letter of Credit.

7. The amount set forth in paragraph 3 of this Certificate does not exceed the amount available to be drawn under the Letter of Credit in respect of payment of principal of the Bonds and was computed in accordance with the terms and conditions of the Bonds, the Indenture and the Letter of Credit.

8. Drawn under Bank of Montreal, acting through its Chicago Branch, Irrevocable Letter of Credit, No. **[_________]**: Pay the amount of $[____________] in principal of the Bonds as certified above.

IN WITNESS WHEREOF, the Trustee has executed and delivered this Certificate as of the ___ day of __________________, 20___.

U.S. BANK NATIONAL ASSOCIATION, as Trustee

By ____________________________________
Name ________________________________
Title _________________________________

EXHIBIT C

CERTIFICATE FOR PURCHASE DRAWING

$85,160,000
NORTHERN CALIFORNIA POWER AGENCY
HYDROELECTRIC PROJECT NUMBER ONE REVENUE BONDS
2008 REFUNDING SERIES A

IRREVOCABLE LETTER OF CREDIT NO. [________]

The undersigned, a duly authorized officer of U.S. Bank National Association (the *"Trustee"* and the *"Tender Agent"*), hereby certifies to the Bank of Montreal, acting through its Chicago Branch (the *"Bank"*), with reference to Irrevocable Letter of Credit No. **[________]** (the *"Letter of Credit"*; any capitalized term used herein and not defined shall have its respective meaning as set forth in the Letter of Credit) issued by the Bank in favor of the Trustee and Tender Agent, that:

1. The Tender Agent is the Tender Agent under the Indenture and is making this demand for payment of the Purchase Price of Bonds tendered or deemed to have been tendered pursuant to: [check (a) or (b) as applicable]

______ (a) an Optional Tender in accordance with Section **[404(a)][404(b)]** of the Supplemental Indenture; or

______ (b) a Mandatory Tender in accordance with Section **[404(d)][404(e)]** of the Supplemental Indenture.

2. (a) The portion of the Purchase Price corresponding to unpaid interest to have accrued, if any, on such Bonds to the date on which such Bonds are to be purchased (the *"Purchase Date")* equals $__________.

(b) The portion of the Purchase Price corresponding to unpaid principal of such Bonds equals $______.

(c) The Purchase Price of such Bonds equals $______, the sum of (a) plus (b).

(d) The amount of moneys which are to be applied pursuant to Section 415(b) of the Supplemental Indenture to the payment of the Purchase Price prior to funds drawn under the Letter of Credit equals $______.

3. Demand is hereby made under the Letter of Credit for $______, which amount does not exceed (a) the amount in paragraph 2(c) less the amount in paragraph 2(d), (b) in the case of the portion of such Purchase Price corresponding to the interest on such Bonds, the Interest Portion of the Stated Amount, or (c) in the case of the portion of such Purchase Price corresponding to the principal of such Bonds, the Principal Portion of the Stated Amount.

4. The amount demanded hereunder does not include any amount payable with respect to an Excluded Bond or an Excluded Drawing as described in Paragraph 13 of the Letter of Credit.

5. The proceeds hereof shall be deposited in the Liquidity Facility Purchase Account of the 2008 Series A Bond Purchase Fund (as defined in the Supplemental Indenture) and held in trust for the sole benefit of the Bank until such proceeds are (a) used to purchase Bonds at the Purchase Price against delivery of such Bonds (or Bonds issued in lieu thereof) as prescribed in Section 2.03 of the Reimbursement Agreement or (b) returned to the Bank.

6. (a) Payment of this demand for payment is requested on or before 2:30 p.m. on the later of (i) the Purchase Date (or if the Purchase Date is not a Business Day, the next succeeding Business Day) and (ii) the Business Day on which this Certificate is received or deemed to have been received by the Bank in accordance with Paragraph 7(a) of the Letter of Credit.

(b) Payment of this demand for payment shall be made in accordance with the payment instructions provided in Paragraph 7(b) of the Letter of Credit.

7. The amount set forth in paragraph 3 of this Certificate does not exceed the amount available on the date hereof to be drawn under the Letter of Credit in respect of the Purchase Price of Eligible Bonds, and was computed in accordance with the terms and conditions of the Bonds, the Indenture and the Letter of Credit.

8. Drawn under Bank of Montreal, acting through its Chicago Branch, Irrevocable Letter of Credit No. **[________]**: Pay the amount of $[_____________] in Purchase Price of the Bonds as certified above.

IN WITNESS WHEREOF, the Tender Agent has executed and delivered this Certificate as of the _____ day of ___________, 20__.

U.S. BANK NATIONAL ASSOCIATION, as Trustee

By ____________________________________
Name ________________________________
Title _________________________________

EXHIBIT D

CERTIFICATE REGARDING REDUCTION OF STATED AMOUNT

$85,160,000
NORTHERN CALIFORNIA POWER AGENCY
HYDROELECTRIC PROJECT NUMBER ONE REVENUE BONDS
2008 REFUNDING SERIES A

IRREVOCABLE LETTER OF CREDIT NO. [________]

The undersigned, a duly authorized officer of U.S. Bank National Association (the *"Trustee"*), hereby certifies to the Bank of Montreal, acting through its Chicago Branch (the *"Bank"*), with reference to Irrevocable Letter of Credit No. **[________]** (the *"Letter of Credit"*; any capitalized term used herein and not defined shall have its respective meaning as set forth in the Letter of Credit) issued by the Bank in favor of the Trustee, that:

1. The Trustee is the Trustee under the Indenture.

2. Bonds in the aggregate principal amount of $___________ were paid or deemed to have been paid pursuant to Section 1301 of the Original Indenture and Section 607 of the Supplemental Indenture on _____________.

3. ______days' interest at _____% per annum (based on a year of _____ days) on the principal amount of the Bonds referenced in paragraph (1) is $_____________.

4. Pursuant to Paragraph 3 of the Letter of Credit, the Stated Amount shall be reduced automatically by $_____________, such reduction to be allocated so that the Principal Portion and the Interest Portion of the Stated Amount shall be reduced by the amounts stated in paragraphs (1) and (2), respectively, upon receipt by the Bank of this Certificate.

IN WITNESS WHEREOF, the Trustee has executed and delivered this Certificate as of the _____ day of ___________, 20__.

U.S. BANK NATIONAL ASSOCIATION, as Trustee

By ____________________________________
Name ________________________________
Title _________________________________

EXHIBIT E

TERMINATION CERTIFICATE—DEFEASANCE/REDEMPTION

$85,160,000
NORTHERN CALIFORNIA POWER AGENCY
HYDROELECTRIC PROJECT NUMBER ONE REVENUE BONDS
2008 REFUNDING SERIES A

IRREVOCABLE LETTER OF CREDIT NO. [_________]

The undersigned, a duly authorized officer of U.S. Bank National Association (the *"Trustee"*), hereby certifies to the Bank of Montreal, acting through its Chicago Branch (the *"Bank"*), with reference to Irrevocable Letter of Credit No. **[_________]** (the *"Letter of Credit"*; any capitalized term used herein and not defined shall have its respective meaning as set forth in the Letter of Credit) issued by the Bank in favor of the Trustee, that all Outstanding Eligible Bonds have been paid or deemed paid in full in accordance with Section 1301 of the Original Indenture and Section 607 of the Supplemental Indenture.

1. The Trustee is the Trustee under the Indenture.

2, The original Letter of Credit, including all amendments, if any, is attached hereto and being surrendered to you herewith.

IN WITNESS WHEREOF, the Trustee has executed and delivered this Certificate as of the ____ day of ____________, 20___.

U.S. BANK NATIONAL ASSOCIATION, as Trustee

By ______________________________________
Name ________________________________
Title _________________________________

EXHIBIT F

TERMINATION CERTIFICATE—CONVERSION

$85,160,000
NORTHERN CALIFORNIA POWER AGENCY
HYDROELECTRIC PROJECT NUMBER ONE REVENUE BONDS
2008 REFUNDING SERIES A

IRREVOCABLE LETTER OF CREDIT NO. [________]

The undersigned, a duly authorized officer of U.S. Bank National Association (the *"Trustee"*), hereby certifies to the Bank of Montreal, acting through its Chicago Branch (the *"Bank"*), with reference to Irrevocable Letter of Credit No. **[________]** (the *"Letter of Credit"*; any capitalized term used herein and not defined shall have its respective meaning as set forth in the Letter of Credit) issued by the Bank in favor of the Trustee, as follows that all Bonds have been converted to bear interest at a rate other than a Covered Rate.

1. The Trustee is the Trustee under the Indenture.

2. There are no Bank Bonds and all principal, interest, fees and other amounts owing under or in connection with the Bank Bonds and the Reimbursement Agreement have been paid to the Bank as of the date hereof.

The original Letter of Credit, including all amendments, if any, is attached hereto and being surrendered to you herewith.

IN WITNESS WHEREOF, the Trustee has executed and delivered this Certificate as of the ____ day of ________________, 20___.

U.S. BANK NATIONAL ASSOCIATION, as Trustee

By ______________________________________
Name ___________________________________
Title ____________________________________

EXHIBIT G

TERMINATION CERTIFICATE—ALTERNATE CREDIT FACILITY

$85,160,000
NORTHERN CALIFORNIA POWER AGENCY
HYDROELECTRIC PROJECT NUMBER ONE REVENUE BONDS
2008 REFUNDING SERIES A

IRREVOCABLE LETTER OF CREDIT NO. [________]

The undersigned, a duly authorized officer of U.S. Bank National Association (the *"Trustee"*), hereby certifies to the Bank of Montreal, acting through its Chicago Branch (the *"Bank"*), with reference to Irrevocable Letter of Credit No. **[________]** (the *"Letter of Credit"*; any capitalized term used herein and not defined shall have its respective meaning as set forth in the Letter of Credit) issued by the Bank in favor of the Trustee. The Trustee has accepted delivery of an Alternate Credit Facility in substitution for the Letter of Credit in accordance with the terms of the Indenture.

1. The Trustee is the Trustee under the Indenture.

2. The original Letter of Credit, including all amendments, if any, is attached hereto and being surrendered to you herewith.

IN WITNESS WHEREOF, the Trustee has executed and delivered this Certificate as of the ____ day of _____________, 20___.

U.S. BANK NATIONAL ASSOCIATION, as Trustee

By ____________________________________
Name ________________________________
Title _________________________________

EXHIBIT H

NOTICE OF TRANSFER

[Date]

Bank of Montreal, Chicago, Illinois
____
____
____
Attention: ________________
Facsimile: ________________
Telephone: ________________

Re: $85,160,000
Northern California Power Agency
Hydroelectric Project Number One Revenue Bonds
2008 Refunding Bonds Series A
Irrevocable Letter of Credit No. **[________]**

Ladies and Gentlemen:

For value received, the undersigned beneficiary hereby irrevocably transfers to:

____
(Name of Transferee)

____
(Address)

all rights of the undersigned beneficiary to draw under the above Letter of Credit in its entirety. Any capitalized term used herein and not defined shall have its respective meaning as set forth in Letter of Credit No. **[________]** issued by you in connection with the above-referenced Bonds.

By this transfer, all rights of the undersigned beneficiary in such Letter of Credit are transferred to the transferee and the transferee shall have the sole rights as beneficiary thereof, including sole rights relating to any amendments, whether increases or extensions or other amendments and whether now existing or hereafter made. All amendments are to be advised directly to the transferee without necessity of any consent of or notice to the undersigned beneficiary.

By its signature below the undersigned transferee acknowledges that it has duly succeeded as Trustee and Tender Agent under the Indenture.

The original of the Letter of Credit (and any amendments thereto) is returned herewith, and we ask you to endorse the transfer requested hereby on the Letter of Credit, and forward it directly to the Transferee with your customary notice of transfer.

The Transferor acknowledges that you incur no obligation hereunder and that the transfer shall not be effective until you have expressly consented to effect the transfer by notice to the Transferee.

Payment of your transfer fee of U.S. $_____________ is for the account of NCPA (as defined in the Letter of Credit) who agrees to pay you on demand any expense or cost you may incur in connection with the transfer.

Transferor represents and warrants to you that (i) Transferor's execution, delivery, and performance of this Transfer Certificate (a) are within its powers, (b) have been duly authorized, (c) constitute its legal, valid, binding and enforceable obligation, (d) do not contravene any charter provision, by-law, resolution, contract, or other undertaking binding on or affecting it or any of its properties, and (e) do not require any notice, filing or other action to, with, or by any governmental authority, (ii) the enclosed Letter or Credit is original and complete, (iii) there is no outstanding demand or request for payment or transfer under the Letter of Credit affecting the rights to be transferred, (iv) the Transferee's name and address are correct and complete and the Transferee's use of the Letter of Credit as transferred and the transactions underlying the Letter of Credit and the requested transfer do not violate any applicable United States or other law, rule or regulation, and (v) the Transferee has succeeded the Transferor as Trustee and Tender Agent under the Indenture.

The effective date of the transfer shall be the date hereafter on which you effect the requested transfer by acknowledging this Transfer Certificate and giving notice thereof to Transferee.

Transferor waives any right to trial by jury it may have in any action or proceeding related to or arising out of this Transfer Certificate.

This Transfer Certificate is made subject to ISP98 and is subject to and shall be governed by the laws of the State of New York, without regard to principles of conflict of laws.

Sincerely yours,

(Print Name of Transferor)

(Transferor's Authorized Signature)

(Print Authorized Signers Name and Title)

(Telephone Number/Fax Number)

SIGNATURE VERIFIED

Signature(s) with title(s) conform(s) with that/those on file with us for this individual, entity or company and signer(s) is/are authorized to execute this agreement. We attest that the individual, company or entity has been identified by us in compliance with USA PATRIOT Act procedures of our bank.

(Print Name of Bank)

(Address of Bank)

(City, State, Zip Code)

(Print Name and Title of Authorized Signer)

(Authorized Signature)

(Telephone Number)

(Date)

Acknowledged:

(Print Name of Transferee)

(Transferee's Authorized Signature)

(Print Authorized Signers Name and Title)

(Telephone Number/Fax Number)

SIGNATURE VERIFIED

Signature(s) with title(s) conform(s) with that/those on file with us for this individual, entity or company and signer(s) is/are authorized to execute this agreement. We attest that the individual, company or entity has been identified by us in compliance with USA PATRIOT Act procedures of our bank.

(Print Name of Bank)

(Address of Bank)

(City, State, Zip Code)

(Print Name and Title of Authorized Signer)

(Authorized Signature)

(Telephone Number)

(Date)

EXHIBIT I

TERMINATION EVENT OF DEFAULT NOTICE

$85,160,000
NORTHERN CALIFORNIA POWER AGENCY
HYDROELECTRIC PROJECT NUMBER ONE REVENUE BONDS
2008 REFUNDING SERIES A

IRREVOCABLE LETTER OF CREDIT NO. [________]

The undersigned, a duly authorized officer of the Bank of Montreal, acting through its Chicago Branch (the *"Bank"*) hereby notifies U.S. Bank National Association, (the *"Trustee"*) with reference to Irrevocable Letter of Credit No. **[________]** (the *"Letter of Credit"*; any capitalized term used herein and not defined herein shall have its respective meaning as set forth in the Letter of Credit) issued by the Bank in favor of the Trustee of the following:

An Event of Default has occurred and is continuing under the Reimbursement Agreement, and, in accordance with the terms of Paragraph 1(e) of the Letter of Credit, the Letter of Credit shall automatically terminate on the date which is six (6) Business Days after the Trustee receives this Termination Event of Default Notice unless the Letter of Credit otherwise terminates sooner in accordance with its terms.

[The reduction in the Stated Amount occurring by reason of an Interest Drawing under the Letter of Credit shall not be reinstated as provided in Paragraph 4(a) of the Letter of Credit.]

[In accordance with the rights granted to the Bank pursuant to Section 7.02(a) of the Reimbursement Agreement, the Trustee is hereby directed to cause the Bonds be called for mandatory tender for purchase in accordance with Section 404(e) of the Supplemental Indenture and, upon such tender, to draw on the Letter of Credit an amount, up to the Stated Amount, necessary to effect a mandatory purchase of all Outstanding Eligible Bonds.]

IN WITNESS WHEREOF, the Bank has executed and delivered this Termination Event of Default Notice as of the _____ day of ____________, 20____.

BANK OF MONTREAL, acting through its Chicago Branch

By ______________________________________
Name ________________________________
Title _________________________________

EXHIBIT J

NOTICE OF REINSTATEMENT

$85,160,000
NORTHERN CALIFORNIA POWER AGENCY
HYDROELECTRIC PROJECT NUMBER ONE REVENUE BONDS
2008 REFUNDING SERIES A

IRREVOCABLE LETTER OF CREDIT NO. [________]

The undersigned, a duly authorized officer of U.S. Bank National Association (the *"Trustee"* and the *"Tender Agent"*), hereby certifies to the Bank of Montreal, acting through its Chicago Branch (the *"Bank"*), with reference to Irrevocable Letter of Credit No. **[________]** (the *"Letter of Credit"*; any capitalized term used herein and not defined shall have its respective meaning as set forth in the Letter of Credit) issued by the Bank in favor of the Trustee and the Tender Agent, as follows:

1. ________ is the Remarketing Agent (as defined in the Reimbursement Agreement) under the Indenture.

2. The Tender Agent has been advised by NCPA or the Remarketing Agent that the amount of $______________ paid to the Bank today by NCPA, or by the Remarketing Agent on behalf of NCPA, is a payment made to reimburse the Bank, pursuant to the Reimbursement Agreement, for amounts drawn under the Letter of Credit pursuant to a Purchase Drawing.

3. Of the amount referred to in paragraph 2, (a) $_______________ represents the aggregate principal amount of Bonds resold or to be resold on behalf of NCPA and (b) $_____________ represents accrued and unpaid interest on such Bonds.

4. Upon receipt by the Bank of the amount referred to in paragraph 2, (a) the Principal Portion is to be reinstated by the first amount referred to in paragraph 3(a) (for a Principal Portion of $_____________, (b) the Interest Portion is to be reinstated by $______________ (*i.e.*, 202 days' interest on the first amount referred to in paragraph 3(a) calculated at a rate of twelve percent (12%) per annum based on a year of 365 days) (for an Interest Amount of $_____________, which is 202 days' interest on the Principal Portion, after giving effect to the reinstatement thereof referred to in clause (a) of this paragraph, calculated at a rate of twelve percent (12%) per annum based on a year of 365 days) and (c) the Stated Amount is to be reinstated by the sum of the amounts referred to in the foregoing clauses (a) and (b) (for an Stated Amount of $________________).

IN WITNESS WHEREOF, the Bank has executed and delivered this Notice as of the _____ day of __________, 20__.

U.S. BANK NATIONAL ASSOCIATION, as Trustee

By ______________________________________

Name ________________________________

Title _________________________________

EXHIBIT K

NOTICE OF EXTENSION

[Date]

U.S. Bank National Association, as Trustee
____
____
Attention: ____________

Re: $85,160,000
Northern California Power Agency
Hydroelectric Project Number One Revenue Bonds
2008 Refunding Series A
Irrevocable Letter of Credit No. **[________]**

Ladies and Gentlemen:

The undersigned, a duly authorized officer of the Bank of Montreal, acting through its Chicago Branch (the *"Bank"*), hereby advises you, with reference to Irrevocable Letter of Credit No. **[_________]** (the *"Letter of Credit"*; any capitalized term used herein and not defined shall have its respective meaning as set forth in the Letter of Credit) issued by the Bank in your favor, that:

1. At the request and for the account of NCPA, we hereby extend the date referenced in paragraph 1(a) of the Letter of Credit (as such date may have been extended previously from time to time) to ________________.

2. Except as specifically provided in paragraph (1) above, all of the terms and conditions of the Letter of Credit remain unchanged and in full force and effect.

3. This Notice of Extension is an integral part of the Letter of Credit and shall be attached to the Letter of Credit and made a part thereof.

IN WITNESS WHEREOF, the undersigned, on behalf of the Bank, has executed and delivered this Notice of Extension as of the _____ day of __________, 20__.

BANK OF MONTREAL, acting through its Chicago Branch

By ______________________________
Name ______________________________
Title ______________________________

[FORM OF 2008 SERIES B LETTER OF CREDIT]

BANK OF MONTREAL,
ACTING THROUGH ITS CHICAGO BRANCH

IRREVOCABLE LETTER OF CREDIT

[_______], 2014

September __, 2014
**US $__________
No. **[________]**

U.S. Bank National Association
____
____
Attention: ________________

Re: $2,105,000
Northern California Power Agency
Hydroelectric Project Number One Revenue Bonds
2008 Taxable Refunding Series B

Ladies and Gentlemen:

At the request and for the account of Northern California Power Agency (*"NCPA"*), a joint exercise of powers agency organized and existing under the laws of the State of California pursuant to the Letter of Credit Reimbursement Agreement dated as of **[______]**, 2014, between Bank of Montreal, acting through its Chicago Branch (the *"Bank"*) and NCPA (as amended, supplemented or restated from time to time pursuant to its terms, the *"Reimbursement Agreement"*) between us and NCPA, we hereby establish this Irrevocable Letter of Credit No. **[_________]** (the *"Letter of Credit"*) in your favor as Trustee (the *"Trustee"*) and as Tender Agent (the *"Tender Agent"*) under the Indenture of Trust, dated as of March 1, 1985 (the *"Original Indenture"*), as supplemented by that Seventeenth Supplemental Indenture of Trust dated as of April 1, 2008 (the *"Supplemental Indenture,"* and together with the Original Indenture and as amended or supplemented from time to time pursuant to its terms, the *"Indenture"*), by and between you, in your capacity as Trustee and as Tender Agent, for the benefit of the holders of NCPA's bonds issued under the Indenture and referenced above (the *"Bonds"*) in accordance with the following terms and conditions. Capitalized terms used herein shall have the meanings assigned to such terms in the Reimbursement Agreement.

1. *Termination.* This Letter of Credit automatically shall terminate on the Termination Date. As used herein, *"Termination Date"* shall (except as otherwise specified below in this Paragraph 1) mean 5:00 p.m., New York City time on the earliest of:

(a) September 9, 2019 (the *"Expiration Date"*); provided that, if on or before such date, or such later date to which the term of this Letter of Credit is extended, as provided herein, we provide you with a written notice in the form of Exhibit K hereto that this Letter of Credit shall be extended, the term of this Letter of Credit shall be extended to the date provided in such notice (any date to which the Expiration Date has been extended as herein provided may be extended in a like manner);

(b) the date on which we receive notice from the Trustee in the form of Exhibit E hereto stating that the principal amount of and interest on all of the Bonds has been paid in full or deemed paid in full in accordance with the provisions of Section 1301 of the Original Indenture and Section 507 of the Supplemental Indenture;

(c) the date on which we receive notice from the Trustee in the form of Exhibit F hereto stating that all of the Bonds have been converted to a rate other than a Covered Rate under Section 204 of the Supplemental Indenture but only after we have honored all Drawings made in strict conformity with the terms of this Letter of Credit on or before such date;

(d) the date on which we receive notice from the Trustee in the form of Exhibit G hereto stating that an Alternate Credit Facility has become effective under Sections 406 and 410 of the Supplemental Indenture in substitution for this Letter of Credit but only after we have honored all Drawings made in strict conformity with the terms of this Letter of Credit on or before such date; or

(e) the date which is six (6) Business Days after you have received a Termination Event of Default Notice in the form of Exhibit I hereto.

In the event the Expiration Date shall not be a Business Day, then this Letter of Credit shall expire on the next succeeding Business Day.

2. *Stated Amount.* The maximum aggregate amount available under this Letter of Credit shall be $2,244,796, which amount, as from time to time reduced and reinstated as provided in Paragraphs 3 and 4, is hereinafter referred to as the *"Stated Amount."* Of the Stated Amount, up to $2,105,000 is available for the payment of the unpaid principal of, or the portion of the Purchase Price corresponding to principal of, the Bonds (the *"Principal Portion"*) and up to $139,796 is available for the payment of the unpaid interest accrued on, or the portion of the Purchase Price corresponding to interest accrued on, the Bonds (the *"Interest Portion"*) for the immediately preceding two hundred two (202) days, calculated at a rate of twelve percent (12%) per annum based on a year of 365 days.

3. *Reductions in the Stated Amount.* The Stated Amount shall be reduced automatically from time to time as follows:

(a) Upon our honoring of a Drawing hereunder, the Stated Amount shall be reduced by an amount equal to the amount of such Drawing.

(b) Upon our receipt of your certificate in the form of Exhibit D hereto appropriately completed, the Stated Amount, the Principal Portion and the Interest Portion shall be permanently reduced by an amount equal to the amount specified in such certificate.

Upon such a reduction, we may require you to return the original of this Letter of Credit and to accept in substitution hereof a substitute Letter of Credit for a Stated Amount reflecting such reduction, but otherwise identical in form and substance to this Letter of Credit.

4. *Reinstatement.* (a) Reductions under Paragraph 3(a) with respect to any Interest Drawing shall be reinstated on the sixth (6th) Business Day following such Drawing unless (i) you receive from us before the close of business on the fifth (5th) Business Day after such Drawing was honored by us a notice in the form of Exhibit I hereto stating that an Event of Default has occurred under the Reimbursement Agreement and, as a result thereof, the amount of such Interest Drawing will not be reinstated and directing you to cause a mandatory tender for purchase of all Bonds pursuant to the Indenture or (ii) such sixth Business Day falls after the Expiration Date.

(b) Reductions under Paragraph 3(a) with respect to any Purchase Drawing to pay the Purchase Price of Eligible Bonds tendered or deemed to have been tendered pursuant to Section 404(a) of the Supplemental Indenture (an *"Optional Tender"*) shall be reinstated upon the Bank's receipt of a certificate in the form of Exhibit J hereto and receipt of the amounts described in such certificate. Any such reinstatement shall be in an amount equal to the amount indicated in such certificate.

(c) Reductions under Paragraph 3(b) shall not be subject to reinstatement. Reductions under Paragraph 3(a) with respect to any Drawing to pay the (i) principal of the Bonds or (ii) Purchase Price of Bonds tendered or deemed to have been tendered pursuant to Sections 404(b) or 404(c) of the Supplemental Indenture (each, a *"Mandatory Tender"* and together with any Optional Tender, a *"Tender"*) shall not be subject to reinstatement.

5. *Documents To Be Presented.* Funds under this Letter of Credit are available to you, against:

(a) in the case of a demand for payment of scheduled and unpaid interest accrued on the Bonds, a certificate signed by you in the form of Exhibit A hereto appropriately completed (an *"Interest Drawing"*);

(b) in the case of a demand for payment of the unpaid principal of the Bonds, a certificate signed by you in the form of Exhibit B hereto appropriately completed (a *"Principal Drawing"*); and

(c) in the case of a demand for payment of the Purchase Price of Bonds pursuant to a Tender, a certificate signed by you in the form of Exhibit C hereto appropriately completed (a *"Purchase Drawing"*).

6. *Method and Notice of Presentment.* The certificates referenced in Paragraph 5 (each a *"Drawing"*), and any other certificate or notice required or permitted to be provided to us hereunder, shall be in writing and dated the date of presentation and, in the case of each Drawing and the certificates in the form of Exhibits E, F, G and J hereto, respectively, shall be delivered to us by facsimile; and, in all other cases, shall be delivered to us at the address stated in paragraph 14 hereof, in person, by first class registered or certified mail or by an express delivery service. A Drawing (and any certificate in the form of Exhibits E, F, G and J hereto) shall be presented by facsimile on or after the date of this Letter of Credit during our business hours on a Business Day on or prior to the Termination Date at our office at Bank of Montreal, acting through its Chicago Branch, at facsimile number ________________, or at any other number or numbers which may be designated by the Bank by written notice delivered to you. The certifications the Trustee and Tender Agent is required to submit to the Bank should be on the Trustee's and Tender Agent's letterhead and purportedly signed by an authorized officer of the Trustee and Tender Agent.

7. *Time and Method for Payment.* Payments made hereunder shall be made in accordance with the instructions specified by the Tender Agent in the drawing certificate relating to a particular Drawing hereunder. (a) If a Drawing is made by you in strict conformity with the terms and conditions of this Letter of Credit, we will honor the Drawing (i) in the case of a Principal Drawing or an Interest Drawing, if such Drawing is received by us prior to 3:00 p.m. on a Business Day, not later than 2:00 p.m. on the next succeeding Business Day or such later date as you may specify in such Drawing; and (ii) in the case of a Purchase Drawing, if such Drawing is received by us prior to 11:30 a.m. on a Business Day, not later than 2:30 p.m. on such Business Day or such later date as you may specify in such Drawing. If a Drawing is received by us on a day which is not a Business Day or is received after 3:00 p.m. (in the case of a Principal Drawing or an Interest Drawing) or after 11:30 a.m. (in the case of a Purchase Drawing) on a Business Day, such Drawing shall be deemed to have been received by us on the next Business Day, and we will honor such Drawing (in the case of a Principal Drawing or an Interest Drawing) by 2:00 p.m. on the Business Day next succeeding the Business Day on which the Drawing is deemed to have been received by us or (in the case of a Purchase Drawing) by 2:30 p.m. on the Business Day on which the Drawing is deemed to have been received by us; provided in any case that the Business Day on which a Drawing is requested to be honored by us in accordance with the terms of this Paragraph 7 is on or prior to the Termination Date. All times referenced herein are as of New York City time.

(b) Unless otherwise agreed, payment under this Letter of Credit shall be made by Fedwire in immediately available funds to **[________________]**. For the purposes of determining compliance with the times for payment specified in subparagraph (a) above, payment shall be deemed to have been made by us when we have delivered appropriate wire transfer instructions to an appropriate Federal Reserve Bank.

(c) All payments made by the Bank under this Letter of Credit shall be made with the Bank's own funds and not with the funds of any other Person.

8. *Other Documents in the Case of Payment, Conversion or Substitution.* You agree to provide to us a duly completed certificate (a) in the form of Exhibit E hereto upon the payment

or deemed payment of all principal of and interest on the Bonds in full as described in Paragraph 1(b), (b) in the form of Exhibit F hereto upon the Conversion of all of the Bonds to a rate other than a Covered Rate as set forth in Paragraph 1(c), and (c) in the form of Exhibit G hereto upon the delivery of an Alternate Credit Facility in substitution for this Letter of Credit as set forth in Paragraph 1(d); and you agree that each such certificate shall be provided upon the occurrence of such payment, conversion or delivery.

9. *Transferability.* This Letter of Credit is transferable in its entirety, but not in part, to any transferee who has succeeded you as Trustee and as Tender Agent under the Indenture and may be successively transferred; *provided* that under no circumstances shall this Letter of Credit be transferred to any person or entity with which U.S. persons or entities are prohibited from conducting business under U.S. Foreign Assets Control Regulations or any other applicable U.S. laws and regulations or to any person or entity with which the Bank is prohibited from doing business pursuant to the Bank's policies. Transfer of this Letter of Credit to such transferee shall be effected by your presentation to us of the original of this Letter of Credit, including all amendments, if any, hereto accompanied by a certificate designating the Trustee's and Tender Agent's successor in the form of Exhibit H hereto, with the signature of the appropriate officer signing on the Trustee's and Tender Agent's behalf verified by an officer of the Trustee's and Tender Agent's bank.

10. *Governing Law and Practices.* This Letter of Credit is governed by, and construed in accordance with, the International Standby Practices (1998), International Chamber of Commerce, Publication No. 590 (the *"ISP98"*). As to matters not governed by ISP98, this Letter of Credit shall be governed by and construed in accordance with the laws of the State of New York, including, without limitation, the Uniform Commercial Code as in effect in the State of New York, without regard to conflict of laws.

11. *Irrevocability.* This Letter of Credit shall be irrevocable.

12. *No Negotiation.* A Drawing under this Letter of Credit shall be presented directly to us by you or by any transferee who has succeeded you as Trustee and as Tender Agent under the Indenture and shall not be negotiated to or by any third party.

13. *Excluded Bonds, Excluded Drawings.* Notwithstanding any other provision of this Letter of Credit, no Drawing under this Letter of Credit may be made (a) by presentation of a Drawing prior to the date hereof or after the Termination Date, (b) requesting that such Drawing be paid after the Termination Date, (c) with respect to any Bank Bond, any Bond bearing interest at a rate other than a Covered Rate, or any Bond registered in the name of, or to the best of your knowledge held for the account or benefit of, NCPA, or any Affiliate of NCPA, or a Person who is a guarantor of any of the obligations of NCPA with respect to the Bonds (each an *"Excluded Bond"* and each Bond that is not an Excluded Bond, an *"Eligible Bond"*), or (d) for the payment of any redemption or prepayment premium (any Drawing described in any of (a) through (d) being an *"Excluded Drawing"*). For the purposes of this Letter of Credit, "*Affiliate*" means, with respect to any Person, any other Person directly or indirectly controlling, controlled by or under common control with such Person (and *"control"* (including *"controlled by"* and *"under common control with"*) means the power, directly or indirectly, to direct or cause the direction of

the management and policies of such Person, whether through the ownership of voting securities or by contract or otherwise).

14. *Address for Communications.* Communications with respect to this Letter of Credit (other than the presentation of Drawings) shall be in writing and shall be addressed to us at Bank of Montreal, ________________, specifically referring thereon to our Irrevocable Letter of Credit No. **[_______]**. At the time any such communications are sent, copies of such communications shall also be sent by facsimile to us at Bank of Montreal, acting through its Chicago Branch, at facsimile number ________________; *provided, however,* that the failure to send such copies shall not affect our obligations hereunder. For telephone assistance, please contact the ________________, and have the Letter of Credit number available. Communications with respect to the Trustee or Tender Agent shall either be sent by first class registered or certified mail or express courier service, properly addressed and prepaid, or physically delivered to the address set forth on the first page of this Letter of Credit.

15. *Complete Agreement.* This Letter of Credit, including Exhibits A through K hereto, sets forth in full the terms of our undertaking. Reference in this Letter of Credit to other documents or instruments is for identification purposes only and any such reference (including, without limitation, the use herein of terms defined in the Reimbursement Agreement) shall not modify, amend, amplify, limit or otherwise affect the terms of our undertaking or cause such documents or instruments to be deemed incorporated herein.

[REMAINDER OF PAGE INTENTIONALLY LEFT BLANK]

We hereby agree with you to honor your Drawings presented in strict compliance with the terms and conditions of this Letter of Credit.

Very truly yours,

BANK OF MONTREAL, acting through its Chicago Branch, as Bank

By ____________________________________
Name ________________________________
Title ________________________________

EXHIBIT A

CERTIFICATE FOR INTEREST DRAWING

$2,105,000
NORTHERN CALIFORNIA POWER AGENCY
HYDROELECTRIC PROJECT NUMBER ONE REVENUE BONDS
2008 TAXABLE REFUNDING SERIES B

IRREVOCABLE LETTER OF CREDIT NO. [________]

The undersigned, a duly authorized officer of U.S. Bank National Association (the *"Trustee"*), hereby certifies to the Bank of Montreal, acting through its Chicago Branch (the *"Bank"*), with reference to Irrevocable Letter of Credit No. **[________]** (the *"Letter of Credit"*; any capitalized term used herein and not defined shall have its respective meaning as set forth in the Letter of Credit) issued by the Bank in favor of the Trustee, that:

1. The Trustee is the Trustee under the Indenture and is making this demand for payment of interest accrued on the Bonds in accordance with the Indenture, which interest is payable on ______________ (the *"Payment Date"*).

2. The amount of interest on the Bonds that is payable on the Payment Date equals $______________.

3. Demand is hereby made under the Letter of Credit for $______________, which amount does not exceed (i) the amount in paragraph (2) or (ii) the Interest Portion of the Stated Amount.

4. The amount demanded hereunder does not include any amount payable with respect to an Excluded Bond or an Excluded Drawing as described in Paragraph 13 of the Letter of Credit.

5. The proceeds hereof shall be deposited in the 2008 Series B Credit Facility Fund (as defined in the Supplemental Indenture) and shall be applied solely to the payment of unpaid interest on the Bonds in accordance with Section 306(b) of the Supplemental Indenture.

(a) Payment of this demand for payment is requested on or before 2:00 p.m., on the later of (i) the Payment Date (or if the Payment Date is not a Business Day, the next succeeding Business Day) and (ii) the Business Day next succeeding the Business Day on which this Certificate is received or deemed to have been received by the Bank in accordance with Paragraph 7(a) of the Letter of Credit.

(b) Payment of this demand for payment shall be made in accordance with the payment instructions provided in Paragraph 7(b) of the Letter of Credit.

6. The amount set forth in paragraph 3 of this Certificate does not exceed the amount available on the date hereof to be drawn under the Letter of Credit in respect of payment of interest accrued on the Bonds on or prior to their stated maturity date or to the redemption or prepayment date, as the case may be, and the amount set forth in paragraph 3 of this Certificate was computed in accordance with the terms and conditions of the Bonds, the Indenture and the Letter of Credit.

7. Drawn under Bank of Montreal, acting through its Chicago Branch, Irrevocable Letter of Credit No. **[________]**: Pay the amount of $[_____________] in interest with respect to the Bonds as certified above.

IN WITNESS WHEREOF, the Trustee has executed and delivered this Certificate as of the ___ day of ___________, 20__.

U.S. BANK NATIONAL ASSOCIATION, as Trustee

By ___________________________________
Name ________________________________
Title _________________________________

EXHIBIT B

CERTIFICATE FOR PRINCIPAL DRAWING

$2,105,000
NORTHERN CALIFORNIA POWER AGENCY
HYDROELECTRIC PROJECT NUMBER ONE REVENUE BONDS
2008 TAXABLE REFUNDING SERIES B

IRREVOCABLE LETTER OF CREDIT NO. [________]

The undersigned, a duly authorized officer of U.S. Bank National Association (the *"Trustee"*), hereby certifies to the Bank of Montreal, acting through its Chicago Branch (the *"Bank"*), with reference to Irrevocable Letter of Credit No. **[________]** (the *"Letter of Credit"*; any capitalized term used herein and not defined shall have its respective meaning as set forth in the Letter of Credit) issued by the Bank in favor of the Trustee, that:

1. The Trustee is the Trustee under the Indenture and is making this demand for payment of principal of the Bonds in accordance with the Indenture, which principal is payable on ________________ (the *"Payment Date"*), by reason of: **[check (a), (b) or (c) as applicable]**

______ (a) scheduled maturity;

______ (b) redemption in whole or in part;

______ (c) the occurrence of an Event of Default (as defined in the Indenture) under the Indenture and declaration of acceleration thereunder.

2. The amount of principal of the Bonds that is payable on the Payment Date equals $_____________.

3. Demand is hereby made under the Letter of Credit for $_____________, which amount does not exceed (i) the amount in paragraph (2) or (ii) the Principal Portion of the Stated Amount.

4. The amount demanded hereunder does not include any amount payable with respect to an Excluded Bond or an Excluded Drawing as described in Paragraph 13 of the Letter of Credit.

5. The proceeds hereof shall be deposited in the 2008 Series B Credit Facility Fund (as defined in the Supplemental Indenture) and shall be applied solely to the payment of the principal of Bonds in accordance with Section 306(b) of the Supplemental Indenture.

6. (a) Payment of this demand for payment is requested on or before 2:00 p.m., on the later of (i) the Payment Date (or if the Payment Date is not a Business Day, the next succeeding

Business Day) and (ii) the Business Day next succeeding the Business Day on which this Certificate is received or deemed to have been received by the Bank in accordance with Paragraph 7(a) of the Letter of Credit.

(b) Payment of this demand for payment shall be made in accordance with the payment instructions provided in Paragraph 7(b) of the Letter of Credit.

7. The amount set forth in paragraph 3 of this Certificate does not exceed the amount available to be drawn under the Letter of Credit in respect of payment of principal of the Bonds and was computed in accordance with the terms and conditions of the Bonds, the Indenture and the Letter of Credit.

8. Drawn under Bank of Montreal, acting through its Chicago Branch, Irrevocable Letter of Credit, No. **[_________]**: Pay the amount of $[____________] in principal of the Bonds as certified above.

IN WITNESS WHEREOF, the Trustee has executed and delivered this Certificate as of the ___ day of __________________, 20___.

U.S. BANK NATIONAL ASSOCIATION, as Trustee

By ____________________________________
Name ________________________________
Title _________________________________

EXHIBIT C

CERTIFICATE FOR PURCHASE DRAWING

$2,105,000
NORTHERN CALIFORNIA POWER AGENCY
HYDROELECTRIC PROJECT NUMBER ONE REVENUE BONDS
2008 TAXABLE REFUNDING SERIES B

IRREVOCABLE LETTER OF CREDIT NO. [________]

The undersigned, a duly authorized officer of U.S. Bank National Association (the *"Trustee"* and the *"Tender Agent"*), hereby certifies to the Bank of Montreal, acting through its Chicago Branch (the *"Bank"*), with reference to Irrevocable Letter of Credit No. **[________]** (the *"Letter of Credit"*; any capitalized term used herein and not defined shall have its respective meaning as set forth in the Letter of Credit) issued by the Bank in favor of the Trustee and Tender Agent, that:

1. The Tender Agent is the Tender Agent under the Indenture and is making this demand for payment of the Purchase Price of Bonds tendered or deemed to have been tendered pursuant to: [check (a) or (b) as applicable]

______ (a) an Optional Tender in accordance with Section 404(a) of the Supplemental Indenture; or

______ (b) a Mandatory Tender in accordance with Section **[404(b)][404(c)]** of the Supplemental Indenture.

2. (a) The portion of the Purchase Price corresponding to unpaid interest to have accrued, if any, on such Bonds to the date on which such Bonds are to be purchased (the *"Purchase Date")* equals $__________.

(b) The portion of the Purchase Price corresponding to unpaid principal of such Bonds equals $______.

(c) The Purchase Price of such Bonds equals $______, the sum of (a) plus (b).

(d) The amount of moneys which are to be applied pursuant to Section 415(b) of the Supplemental Indenture to the payment of the Purchase Price prior to funds drawn under the Letter of Credit equals $______.

3. Demand is hereby made under the Letter of Credit for $______, which amount does not exceed (a) the amount in paragraph 2(c) less the amount in paragraph 2(d), (b) in the case of the portion of such Purchase Price corresponding to the interest on such Bonds, the Interest Portion of the Stated Amount, or (c) in the case of the portion of such Purchase Price corresponding to the principal of such Bonds, the Principal Portion of the Stated Amount.

4. The amount demanded hereunder does not include any amount payable with respect to an Excluded Bond or an Excluded Drawing as described in Paragraph 13 of the Letter of Credit.

5. The proceeds hereof shall be deposited in the Liquidity Facility Purchase Account of the 2008 Series B Bond Purchase Fund (as defined in the Supplemental Indenture) and held in trust for the sole benefit of the Bank until such proceeds are (a) used to purchase Bonds at the Purchase Price against delivery of such Bonds (or Bonds issued in lieu thereof) as prescribed in Section 2.03 of the Reimbursement Agreement or (b) returned to the Bank.

6. (a) Payment of this demand for payment is requested on or before 2:30 p.m. on the later of (i) the Purchase Date (or if the Purchase Date is not a Business Day, the next succeeding Business Day) and (ii) the Business Day on which this Certificate is received or deemed to have been received by the Bank in accordance with Paragraph 7(a) of the Letter of Credit.

(b) Payment of this demand for payment shall be made in accordance with the payment instructions provided in Paragraph 7(b) of the Letter of Credit.

7. The amount set forth in paragraph 3 of this Certificate does not exceed the amount available on the date hereof to be drawn under the Letter of Credit in respect of the Purchase Price of Eligible Bonds, and was computed in accordance with the terms and conditions of the Bonds, the Indenture and the Letter of Credit.

8. Drawn under Bank of Montreal, acting through its Chicago Branch, Irrevocable Letter of Credit No. **[________]**: Pay the amount of $[_____________] in Purchase Price of the Bonds as certified above.

IN WITNESS WHEREOF, the Tender Agent has executed and delivered this Certificate as of the _____ day of ___________, 20__.

U.S. BANK NATIONAL ASSOCIATION, as Trustee

By ____________________________________
Name ______________________________
Title ________________________________

EXHIBIT D

CERTIFICATE REGARDING REDUCTION OF STATED AMOUNT

$2,105,000
NORTHERN CALIFORNIA POWER AGENCY
HYDROELECTRIC PROJECT NUMBER ONE REVENUE BONDS
2008 TAXABLE REFUNDING SERIES B

IRREVOCABLE LETTER OF CREDIT NO. [________]

The undersigned, a duly authorized officer of U.S. Bank National Association (the *"Trustee"*), hereby certifies to the Bank of Montreal, acting through its Chicago Branch (the *"Bank"*), with reference to Irrevocable Letter of Credit No. **[________]** (the *"Letter of Credit"*; any capitalized term used herein and not defined shall have its respective meaning as set forth in the Letter of Credit) issued by the Bank in favor of the Trustee, that:

1. The Trustee is the Trustee under the Indenture.

2. Bonds in the aggregate principal amount of $___________were paid or deemed to have been paid pursuant to Section 1301 of the Original Indenture and Section 507 of the Supplemental Indenture on _____________.

3. ______days' interest at _____% per annum (based on a year of _____ days) on the principal amount of the Bonds referenced in paragraph (1) is $_____________.

4. Pursuant to Paragraph 3 of the Letter of Credit, the Stated Amount shall be reduced automatically by $_____________, such reduction to be allocated so that the Principal Portion and the Interest Portion of the Stated Amount shall be reduced by the amounts stated in paragraphs (1) and (2), respectively, upon receipt by the Bank of this Certificate.

IN WITNESS WHEREOF, the Trustee has executed and delivered this Certificate as of the _____ day of ___________, 20__.

U.S. BANK NATIONAL ASSOCIATION, as Trustee

By ____________________________________
Name ________________________________
Title _________________________________

EXHIBIT E

TERMINATION CERTIFICATE—DEFEASANCE/REDEMPTION

$2,105,000
NORTHERN CALIFORNIA POWER AGENCY
HYDROELECTRIC PROJECT NUMBER ONE REVENUE BONDS
2008 TAXABLE REFUNDING SERIES B

IRREVOCABLE LETTER OF CREDIT NO. [_________]

The undersigned, a duly authorized officer of U.S. Bank National Association (the *"Trustee"*), hereby certifies to the Bank of Montreal, acting through its Chicago Branch (the *"Bank"*), with reference to Irrevocable Letter of Credit No. **[_________]** (the *"Letter of Credit"*; any capitalized term used herein and not defined shall have its respective meaning as set forth in the Letter of Credit) issued by the Bank in favor of the Trustee, that all Outstanding Eligible Bonds have been paid or deemed paid in full in accordance with Section 1301 of the Original Indenture and Section 507 of the Supplemental Indenture.

1. The Trustee is the Trustee under the Indenture.

2, The original Letter of Credit, including all amendments, if any, is attached hereto and being surrendered to you herewith.

IN WITNESS WHEREOF, the Trustee has executed and delivered this Certificate as of the ____ day of ____________, 20___.

U.S. BANK NATIONAL ASSOCIATION, as Trustee

By ____________________________________
Name ________________________________
Title ________________________________

EXHIBIT F

TERMINATION CERTIFICATE—CONVERSION

$2,105,000
NORTHERN CALIFORNIA POWER AGENCY
HYDROELECTRIC PROJECT NUMBER ONE REVENUE BONDS
2008 TAXABLE REFUNDING SERIES B

IRREVOCABLE LETTER OF CREDIT NO. [________]

The undersigned, a duly authorized officer of U.S. Bank National Association (the *"Trustee"*), hereby certifies to the Bank of Montreal, acting through its Chicago Branch (the *"Bank"*), with reference to Irrevocable Letter of Credit No. **[________]** (the *"Letter of Credit"*; any capitalized term used herein and not defined shall have its respective meaning as set forth in the Letter of Credit) issued by the Bank in favor of the Trustee, as follows that all Bonds have been converted to bear interest at a rate other than a Covered Rate.

1. The Trustee is the Trustee under the Indenture.

2. There are no Bank Bonds and all principal, interest, fees and other amounts owing under or in connection with the Bank Bonds and the Reimbursement Agreement have been paid to the Bank as of the date hereof.

The original Letter of Credit, including all amendments, if any, is attached hereto and being surrendered to you herewith.

IN WITNESS WHEREOF, the Trustee has executed and delivered this Certificate as of the ____ day of ________________, 20___.

U.S. BANK NATIONAL ASSOCIATION, as Trustee

By ______________________________________
Name ________________________________
Title __________________________________

EXHIBIT G

TERMINATION CERTIFICATE—ALTERNATE CREDIT FACILITY

$2,105,000
NORTHERN CALIFORNIA POWER AGENCY
HYDROELECTRIC PROJECT NUMBER ONE REVENUE BONDS
2008 TAXABLE REFUNDING SERIES B

IRREVOCABLE LETTER OF CREDIT NO. [________]

The undersigned, a duly authorized officer of U.S. Bank National Association (the *"Trustee"*), hereby certifies to the Bank of Montreal, acting through its Chicago Branch (the *"Bank"*), with reference to Irrevocable Letter of Credit No. **[________]** (the *"Letter of Credit"*; any capitalized term used herein and not defined shall have its respective meaning as set forth in the Letter of Credit) issued by the Bank in favor of the Trustee. The Trustee has accepted delivery of an Alternate Credit Facility in substitution for the Letter of Credit in accordance with the terms of the Indenture.

1. The Trustee is the Trustee under the Indenture.

2. The original Letter of Credit, including all amendments, if any, is attached hereto and being surrendered to you herewith.

IN WITNESS WHEREOF, the Trustee has executed and delivered this Certificate as of the ____ day of _____________, 20___.

U.S. BANK NATIONAL ASSOCIATION, as Trustee

By ____________________________________
Name ________________________________
Title _________________________________

EXHIBIT H

NOTICE OF TRANSFER

[Date]

Bank of Montreal, Chicago, Illinois
____
____
____
Attention: __________________
Facsimile: __________________
Telephone: __________________

Re: $2,105,000
Northern California Power Agency
Hydroelectric Project Number One Revenue Bonds
2008 Taxable Refunding Series B
Irrevocable Letter of Credit No. **[________]**

Ladies and Gentlemen:

For value received, the undersigned beneficiary hereby irrevocably transfers to:

____
(Name of Transferee)

____
(Address)

all rights of the undersigned beneficiary to draw under the above Letter of Credit in its entirety. Any capitalized term used herein and not defined shall have its respective meaning as set forth in Letter of Credit No. **[________]** issued by you in connection with the above-referenced Bonds.

By this transfer, all rights of the undersigned beneficiary in such Letter of Credit are transferred to the transferee and the transferee shall have the sole rights as beneficiary thereof, including sole rights relating to any amendments, whether increases or extensions or other amendments and whether now existing or hereafter made. All amendments are to be advised directly to the transferee without necessity of any consent of or notice to the undersigned beneficiary.

By its signature below the undersigned transferee acknowledges that it has duly succeeded as Trustee and Tender Agent under the Indenture.

The original of the Letter of Credit (and any amendments thereto) is returned herewith, and we ask you to endorse the transfer requested hereby on the Letter of Credit, and forward it directly to the Transferee with your customary notice of transfer.

The Transferor acknowledges that you incur no obligation hereunder and that the transfer shall not be effective until you have expressly consented to effect the transfer by notice to the Transferee.

Payment of your transfer fee of U.S. $_____________ is for the account of NCPA (as defined in the Letter of Credit) who agrees to pay you on demand any expense or cost you may incur in connection with the transfer.

Transferor represents and warrants to you that (i) Transferor's execution, delivery, and performance of this Transfer Certificate (a) are within its powers, (b) have been duly authorized, (c) constitute its legal, valid, binding and enforceable obligation, (d) do not contravene any charter provision, by-law, resolution, contract, or other undertaking binding on or affecting it or any of its properties, and (e) do not require any notice, filing or other action to, with, or by any governmental authority, (ii) the enclosed Letter or Credit is original and complete, (iii) there is no outstanding demand or request for payment or transfer under the Letter of Credit affecting the rights to be transferred, (iv) the Transferee's name and address are correct and complete and the Transferee's use of the Letter of Credit as transferred and the transactions underlying the Letter of Credit and the requested transfer do not violate any applicable United States or other law, rule or regulation, and (v) the Transferee has succeeded the Transferor as Trustee and Tender Agent under the Indenture.

The effective date of the transfer shall be the date hereafter on which you effect the requested transfer by acknowledging this Transfer Certificate and giving notice thereof to Transferee.

Transferor waives any right to trial by jury it may have in any action or proceeding related to or arising out of this Transfer Certificate.

This Transfer Certificate is made subject to ISP98 and is subject to and shall be governed by the laws of the State of New York, without regard to principles of conflict of laws.

Sincerely yours,

____
(Print Name of Transferor)

____
(Transferor's Authorized Signature)

____
(Print Authorized Signers Name and Title)

____
(Telephone Number/Fax Number)

SIGNATURE VERIFIED

Signature(s) with title(s) conform(s) with that/those on file with us for this individual, entity or company and signer(s) is/are authorized to execute this agreement. We attest that the individual, company or entity has been identified by us in compliance with USA PATRIOT Act procedures of our bank.

____
(Print Name of Bank)

____
(Address of Bank)

____
(City, State, Zip Code)

____
(Print Name and Title of Authorized Signer)

____
(Authorized Signature)

____
(Telephone Number)

____
(Date)

Acknowledged:

____
(Print Name of Transferee)

____
(Transferee's Authorized Signature)

____
(Print Authorized Signers Name and Title)

____
(Telephone Number/Fax Number)

SIGNATURE VERIFIED

Signature(s) with title(s) conform(s) with that/those on file with us for this individual, entity or company and signer(s) is/are authorized to execute this agreement. We attest that the individual, company or entity has been identified by us in compliance with USA PATRIOT Act procedures of our bank.

____
(Print Name of Bank)

____
(Address of Bank)

____
(City, State, Zip Code)

____
(Print Name and Title of Authorized Signer)

____
(Authorized Signature)

____
(Telephone Number)

____
(Date)

EXHIBIT I

TERMINATION EVENT OF DEFAULT NOTICE

$2,105,000
NORTHERN CALIFORNIA POWER AGENCY
HYDROELECTRIC PROJECT NUMBER ONE REVENUE BONDS
2008 TAXABLE REFUNDING SERIES B

IRREVOCABLE LETTER OF CREDIT NO. [________]

The undersigned, a duly authorized officer of the Bank of Montreal, acting through its Chicago Branch (the *"Bank"*) hereby notifies U.S. Bank National Association, (the *"Trustee"*) with reference to Irrevocable Letter of Credit No. **[________]** (the *"Letter of Credit"*; any capitalized term used herein and not defined herein shall have its respective meaning as set forth in the Letter of Credit) issued by the Bank in favor of the Trustee of the following:

An Event of Default has occurred and is continuing under the Reimbursement Agreement, and, in accordance with the terms of Paragraph 1(e) of the Letter of Credit, the Letter of Credit shall automatically terminate on the date which is six (6) Business Days after the Trustee receives this Termination Event of Default Notice unless the Letter of Credit otherwise terminates sooner in accordance with its terms.

[The reduction in the Stated Amount occurring by reason of an Interest Drawing under the Letter of Credit shall not be reinstated as provided in Paragraph 4(a) of the Letter of Credit.]

[In accordance with the rights granted to the Bank pursuant to Section 7.02(a) of the Reimbursement Agreement, the Trustee is hereby directed to cause the Bonds be called for mandatory tender for purchase in accordance with Section 404(c) of the Supplemental Indenture and, upon such tender, to draw on the Letter of Credit an amount, up to the Stated Amount, necessary to effect a mandatory purchase of all Outstanding Eligible Bonds.]

IN WITNESS WHEREOF, the Bank has executed and delivered this Termination Event of Default Notice as of the _____ day of ____________, 20____.

BANK OF MONTREAL, acting through its Chicago Branch

By ______________________________________
Name ________________________________
Title _________________________________

EXHIBIT J

NOTICE OF REINSTATEMENT

$2,105,000
NORTHERN CALIFORNIA POWER AGENCY
HYDROELECTRIC PROJECT NUMBER ONE REVENUE BONDS
2008 TAXABLE REFUNDING SERIES B

IRREVOCABLE LETTER OF CREDIT NO. [________]

The undersigned, a duly authorized officer of U.S. Bank National Association (the *"Trustee"* and the *"Tender Agent"*), hereby certifies to the Bank of Montreal, acting through its Chicago Branch (the *"Bank"*), with reference to Irrevocable Letter of Credit No. **[________]** (the *"Letter of Credit"*; any capitalized term used herein and not defined shall have its respective meaning as set forth in the Letter of Credit) issued by the Bank in favor of the Trustee and the Tender Agent, as follows:

1. ________ is the Remarketing Agent (as defined in the Reimbursement Agreement) under the Indenture.

2. The Tender Agent has been advised by NCPA or the Remarketing Agent that the amount of $______________ paid to the Bank today by NCPA, or by the Remarketing Agent on behalf of NCPA, is a payment made to reimburse the Bank, pursuant to the Reimbursement Agreement, for amounts drawn under the Letter of Credit pursuant to a Purchase Drawing.

3. Of the amount referred to in paragraph 2, (a) $_______________ represents the aggregate principal amount of Bonds resold or to be resold on behalf of NCPA and (b) $_____________ represents accrued and unpaid interest on such Bonds.

4. Upon receipt by the Bank of the amount referred to in paragraph 2, (a) the Principal Portion is to be reinstated by the first amount referred to in paragraph 3(a) (for a Principal Portion of $_____________, (b) the Interest Portion is to be reinstated by $______________ (*i.e.*, 202 days' interest on the first amount referred to in paragraph 3(a) calculated at a rate of twelve percent (12%) per annum based on a year of 365 days) (for an Interest Amount of $_____________, which is 202 days' interest on the Principal Portion, after giving effect to the reinstatement thereof referred to in clause (a) of this paragraph, calculated at a rate of twelve percent (12%) per annum based on a year of 365 days) and (c) the Stated Amount is to be reinstated by the sum of the amounts referred to in the foregoing clauses (a) and (b) (for an Stated Amount of $________________).

IN WITNESS WHEREOF, the Bank has executed and delivered this Notice as of the _____ day of __________, 20__.

U.S. BANK NATIONAL ASSOCIATION, as Trustee

By ______________________________________
Name ________________________________
Title _________________________________

EXHIBIT K

NOTICE OF EXTENSION

[Date]

U.S. Bank National Association, as Trustee
____
____
Attention: ____________

Re: $2,105,000
Northern California Power Agency
Hydroelectric Project Number One Revenue Bonds
2008 Taxable Refunding Series B
Irrevocable Letter of Credit No. **[________]**

Ladies and Gentlemen:

The undersigned, a duly authorized officer of the Bank of Montreal, acting through its Chicago Branch (the *"Bank"*), hereby advises you, with reference to Irrevocable Letter of Credit No. **[_________]** (the *"Letter of Credit"*; any capitalized term used herein and not defined shall have its respective meaning as set forth in the Letter of Credit) issued by the Bank in your favor, that:

1. At the request and for the account of NCPA, we hereby extend the date referenced in paragraph 1(a) of the Letter of Credit (as such date may have been extended previously from time to time) to ________________.

2. Except as specifically provided in paragraph (1) above, all of the terms and conditions of the Letter of Credit remain unchanged and in full force and effect.

3. This Notice of Extension is an integral part of the Letter of Credit and shall be attached to the Letter of Credit and made a part thereof.

IN WITNESS WHEREOF, the undersigned, on behalf of the Bank, has executed and delivered this Notice of Extension as of the _____ day of __________, 20__.

BANK OF MONTREAL, acting through its Chicago Branch

By ______________________________________
Name ________________________________
Title _________________________________

APPENDIX H

ESTIMATED DEBT SERVICE REQUIREMENTS ON THE HYDROELECTRIC PROJECT BONDS

The following table shows the combined estimated annual debt service requirements for the Hydroelectric Project Bonds. Principal amounts set forth in the table below include sinking fund redemptions.

	Outstanding Hydroelectric Project Bonds[1]		
Year Ending July 1	**Principal**	**Interest**	**Total[2]**
2015	$19,105,000	$18,332,089	$37,437,089
2016	20,050,000	17,441,224	37,491,224
2017	21,385,000	16,428,429	37,813,429
2018	22,610,000	15,213,509	37,823,509
2019	22,165,000	13,928,244	36,093,244
2020	23,305,000	12,845,196	36,150,196
2021	24,300,000	11,707,364	36,007,364
2022	25,540,000	10,518,996	36,058,996
2023	30,925,000	9,269,867	40,194,867
2024	30,685,000	7,754,323	38,439,323
2025	14,715,000	6,310,297	21,025,297
2026	15,415,000	5,615,291	21,030,291
2027	16,155,000	4,886,880	21,041,880
2028	16,930,000	4,123,181	21,053,181
2029	17,745,000	3,322,622	21,067,622
2030	18,525,000	2,590,969	21,115,969
2031	19,325,000	1,826,811	21,151,811
2032	24,100,000	1,029,267	25,129,267
Total[1]	$382,980,000	$163,144,563	$546,124,563

(1) Includes outstanding 1992 Refunding Series A Bonds, 2008 Refunding Series A Bonds, 2008 Taxable Refunding Series B Bonds, 2008 Refunding Series C Bonds, 2010 Refunding Series A Bonds, 2012 Refunding Series A Bonds and 2012 Taxable Refunding Series B Bonds. Interest on the variable rate 2008 Refunding Series A Bonds and 2008 Taxable Refunding Series B Bonds has been assumed at the associated fixed swap rate for the 2008 Refunding Series A Bonds and at a fixed rate of 4.00% for the 2008 Refunding Series B Bonds.

(2) Totals may not add due to rounding.

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NORTHERN CALIFORNIA POWER AGENCY • HYDROELECTRIC PROJECT NUMBER ONE REVENUE BONDS, 2008 REFUNDING SERIES A AND 2008 TAXABLE REFUNDING SERIES B

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