In the opinion of Co-Bond Counsel, under existing law, interest on the 2015 Series C Subordinate Bonds is exempt from personal income taxes of the State of California and, assuming compliance with the tax covenants described herein, interest on the 2015 Series C Subordinate Bonds will be excludable from the gross income of the owners thereof for federal income tax purposes and will not be treated as an item of tax preference for purposes of the federal alternative minimum tax. See “TAX MATTERS” herein.

$116,535,000
SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
(a public entity organized under the laws of the State of California)
Transmission Project Revenue Bonds,
2015 Subordinate Refunding Series C
(Southern Transmission Project)

Dated: Date of Delivery
Due: July 1, as shown below

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

The Transmission Project Revenue Bonds, 2015 Subordinate Refunding Series C (the “2015 Series C Subordinate Bonds”) will be issued by the Southern California Public Power Authority (the “Authority”) under and pursuant to an Indenture of Trust, dated as of March 1, 2015, (the “Indenture of Trust”), from the Authority to U.S. Bank National Association, as trustee (the “Trustee”). The 2015 Series C Subordinate Bonds are being issued to provide moneys to refund all of the Authority’s outstanding $125,005,000 Transmission Project Revenue Bonds, 2008 Subordinate Series B (the “Refunded Bonds”) and to pay costs of issuance relating to the 2015 Series C Subordinate Bonds. The Refunded Bonds financed the costs of upgrading two converter stations of the Intermountain Power Project Southern Transmission System, from a rating of 1,920 MW to its current rating of 2,400 MW. See “ESTIMATED SOURCES AND USES OF FUNDS” and “THE AUTHORITY’S REFUNDING PLAN” herein.

The 2015 Series C Subordinate Bonds are being issued as fully registered bonds and, when issued, will be registered in the name of Cede & Co., as nominee of The Depository Trust Company, New York, New York (“DTC”). DTC will act as securities depository of the 2015 Series C Subordinate Bonds. Individual purchases of the 2015 Series C Subordinate Bonds will be made in book-entry form only. Purchasers of the 2015 Series C Subordinate Bonds will not receive physical certificates representing their interest in the 2015 Series C Subordinate Bonds purchased. Principal of, premium, if any, and interest on the 2015 Series C Subordinate Bonds are payable directly to DTC by the Trustee. Upon receipt of payments of such principal, premium, if any, and interest, DTC is obligated to remit such payments relating to the 2015 Series C Subordinate Bonds purchased. See “BOOK-ENTRY ONLY SYSTEM” herein.

The 2015 Series C Subordinate Bonds will be issued in denominations of $5,000 and any integral multiple thereof. The 2015 Series C Subordinate Bonds will be dated their date of delivery and will bear interest at the respective rates set forth on the inside cover hereof. Interest on the 2015 Series C Subordinate Bonds will be payable semiannually on January 1 and July 1 of each year, commencing July 1, 2015, and will be calculated on the basis of a 360-day year consisting of twelve 30-day months. The 2015 Series C Subordinate Bonds will mature on the dates and in the amounts set forth on the inside cover hereof.

The 2015 Series C Subordinate Bonds are subject to optional redemption prior to maturity as described herein. See “DESCRIPTION OF THE 2015 SERIES C SUBORDINATE BONDS – Redemption Provisions” herein.

The principal of, premium if any, and interest on the 2015 Series C Subordinate Bonds are secured solely by and payable solely from Pledged Revenues (defined herein). See “SECURITY AND SOURCES OF PAYMENT FOR THE SENIOR BONDS AND THE SUBORDINATE BONDS” herein. No Senior Bonds are currently outstanding.

The 2015 Series C Subordinate Bonds are not obligations of the State of California, any public agency thereof (other than the Authority), any member of the Authority or the Project Participants and neither the faith and credit nor the taxing power of any of the foregoing (including the Authority) is pledged for the payment of the 2015 Series C Subordinate Bonds. The Authority has no taxing power.

Maturity Schedule
(see inside cover)

The 2015 Series C Subordinate Bonds are offered when, as and if issued and received by the Underwriters, and subject to the approval of legality by Norton Rose Fulbright US LLP, Los Angeles, California, and Curls Bartling P.C., Oakland, California, Co-Bond Counsel, and certain other conditions. Certain legal matters will be passed on for the Authority by its General Counsel, Richard J. Morillo, Esq., and for the Underwriters by their counsel, Sidley Austin LLP, San Francisco, California. Public Financial Management, Inc. is serving as Financial Advisor to the Authority in connection with the issuance of the 2015 Series C Subordinate Bonds. It is expected that the 2015 Series C Subordinate Bonds will be available for delivery through the facilities of DTC in New York, New York, by Fast Automated Securities Transfer (FAST) on or about March 25, 2015.

Morgan Stanley
Dated: February 25, 2015
## Maturity Schedule

**$116,535,000**  
Transmission Project Revenue Bonds, 2015 Subordinate Refunding Series C  
(Southern Transmission Project)

<table>
<thead>
<tr>
<th>Due July 1</th>
<th>Principal Amount</th>
<th>Interest Rate</th>
<th>Yield</th>
<th>CUSIP†</th>
</tr>
</thead>
<tbody>
<tr>
<td>2024</td>
<td>$ 1,680,000</td>
<td>4.000%</td>
<td>2.080%</td>
<td>842477UB5</td>
</tr>
<tr>
<td>2024</td>
<td>25,375,000</td>
<td>5.000</td>
<td>2.080</td>
<td>842477TX9</td>
</tr>
<tr>
<td>2025</td>
<td>200,000</td>
<td>4.000</td>
<td>2.220†</td>
<td>842477UC3</td>
</tr>
<tr>
<td>2025</td>
<td>28,190,000</td>
<td>5.000</td>
<td>2.220†</td>
<td>842477TY7</td>
</tr>
<tr>
<td>2026</td>
<td>610,000</td>
<td>4.000</td>
<td>2.490†</td>
<td>842477UD1</td>
</tr>
<tr>
<td>2026</td>
<td>29,195,000</td>
<td>5.000</td>
<td>2.390†</td>
<td>842477TZ4</td>
</tr>
<tr>
<td>2027</td>
<td>10,225,000</td>
<td>4.000</td>
<td>2.670†</td>
<td>842477UE9</td>
</tr>
<tr>
<td>2027</td>
<td>21,060,000</td>
<td>5.000</td>
<td>2.520†</td>
<td>842477UA7</td>
</tr>
</tbody>
</table>

† CUSIP is a registered trademark of The American Bankers Association. The CUSIP data herein are provided by CUSIP Global Services, managed by Standard & Poor's Financial Services LLC on behalf of The American Bankers Association. These data are not intended to create a database and do not serve in any way as a substitute for the CUSIP Services. Neither the Authority nor the Underwriters are responsible for the selection or correctness of the CUSIP numbers set forth herein.

†† Priced to optional par call on January 1, 2025.
SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

BOARD OF DIRECTORS

Dukku Lee (Anaheim)  Stephen M. Zurn (Glendale)
George Morrow (Azusa)  Kevin E. Kelley (Imperial)
Fred H. Mason (Banning)  Marcie L. Edwards (Los Angeles)
Ronald E. Davis (Burbank)  Phyllis E. Currie (Pasadena)
Art Gallucci (Cerritos)  Girish Balachandran (Riverside)
David X. Kolk (Colton)  Carlos Fandino (Vernon)

MANAGEMENT

Fred H. Mason – President
Girish Balachandran – Vice President
Ann M. Santilli – Secretary
Mario C. Ignacio – Assistant Secretary
Bill D. Carnahan – Executive Director, Treasurer/Auditor
and Assistant Secretary
[vacant] (1) – Director of Finance & Accounting
Richard J. Morillo – General Counsel
Daniel S. Hashimi – Assistant General Counsel

PROJECT PARTICIPANTS

Department of Water and Power of The City of Los Angeles
City of Anaheim  City of Glendale
City of Riverside  City of Pasadena

FINANCIAL ADVISOR

Public Financial Management, Inc.
Los Angeles, California

TRUSTEE AND PAYING AGENT

U.S. Bank National Association
Los Angeles, California

VERIFICATION AGENT

Samuel Klein and Company
Newark, New Jersey

CO-BOND COUNSEL

Norton Rose Fulbright US LLP
Los Angeles, California
and
Curls Bartling P.C.
Oakland, California

(1) Director of Finance & Accounting services are currently being provided under a consulting agreement with Michael Bell Management Consulting.
No dealer, broker, salesperson or other person has been authorized by the Authority or by the Underwriters to give any information or to make any representations, other than as contained in this Official Statement, and if given or made such other information or representations must not be relied upon as having been authorized by the Authority or the Underwriters. This Official Statement does not constitute an offer to sell or the solicitation of an offer to buy, nor shall there be any sale of the 2015 Series C Subordinate Bonds by any person in any jurisdiction in which it is unlawful for such person to make such offer, solicitation or sale.

This Official Statement is not to be construed as a contract with the purchasers of the 2015 Series C Subordinate Bonds. Statements contained in this Official Statement that involve estimates, forecasts or matters of opinion, whether or not expressly described herein, are intended solely as such and are not to be construed as representations of fact.

The information set forth herein has been furnished by the Authority and certain of the Project Participants, and includes information obtained from other sources which are believed to be reliable. The information and expressions of opinion contained herein are subject to change without notice and neither the delivery of this Official Statement nor any sale made hereunder shall, under any circumstances, create any implication that there has been no change in the affairs of the Authority or any Project Participant since the date hereof.

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


Certain statements included or incorporated by reference in this Official Statement constitute “forward-looking statements.” Such statements are generally identifiable by the terminology used such as “plan,” “project,” “expect,” “anticipate,” “intend,” “believe,” “estimate,” “budget” or other similar words. 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. The Authority 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 or fail to occur.

This Official Statement, including any supplement or amendment hereto, is intended to be filed with the Municipal Securities Rulemaking Board through the Electronic Municipal Marketplace (EMMA) website. The Authority also maintains a website. However, the information presented therein is not part of this Official Statement and should not be relied upon in making investment decisions with respect to the 2015 Series C Subordinate Bonds.

References to web site addresses presented herein are for informational purposes only and may be in the form of a hyperlink solely for the reader’s convenience. Unless specified otherwise, such web sites and the information or links contained therein are not incorporated into, and are not part of, this Official Statement for purposes of, and as that term is defined in, SEC Rule 15c2-12.
# TABLE OF CONTENTS

## INTRODUCTION ....................................................................................................................................... 1

- Purpose; Authority for Issuance ........................................................................................................ 1
- Outstanding Bonds; Other Obligations ............................................................................................. 1
- Security and Sources of Payment for the Subordinate Bonds; Other Obligations .......................... 2
- The Authority .................................................................................................................................. 3
- Southern Transmission Project and Authority Capacity ................................................................. 3
- Intermountain Power Project ............................................................................................................. 3
- Payments-In-Aid of Construction ...................................................................................................... 4
- Acquisition of Authority Capacity ..................................................................................................... 4
- Transmission Service ....................................................................................................................... 4
- Continuing Disclosure Undertaking ................................................................................................. 5
- Certain Information; Summaries and References to Documents .................................................... 5

## THE AUTHORITY’S REFUNDING PLAN .............................................................................................. 6

## ESTIMATED SOURCES AND USES OF FUNDS ................................................................................... 7

## ESTIMATED DEBT SERVICE REQUIREMENTS .................................................................................. 7

## DESCRIPTION OF THE 2015 SERIES C SUBORDINATE BONDS ...................................................... 7

- General ............................................................................................................................................ 7
- Redemption Provisions .................................................................................................................... 7

## BOOK-ENTRY ONLY SYSTEM ............................................................................................................... 8

- General ............................................................................................................................................ 8
- Discontinuation of the Book-Entry Only System ........................................................................... 10

## SECURITY AND SOURCES OF PAYMENT FOR THE SENIOR BONDS AND THE SUBORDINATE BONDS .............................................................. 11

- Pledge Effected by the Senior Indenture .......................................................................................... 11
- Pledge Effected by the 2015 Series C Subordinated Indenture ............................................................ 12
- General Limitation on Obligations .................................................................................................... 12
- Transmission Service Contracts ....................................................................................................... 12
- Authority Rate Covenant .................................................................................................................. 15
- Budgeting ....................................................................................................................................... 15
- Flow of Funds ............................................................................................................................... 15
- No Funded 2015 Series C Reserve Account ....................................................................................... 18

## SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY ........................................................................ 18

- Formation ....................................................................................................................................... 18
- Organization and Management ........................................................................................................ 18
- Other Activities of the Authority ..................................................................................................... 19
- Other projects of the Authority not Financed by Bonds .................................................................. 25
- Further Information ........................................................................................................................ 27

## THE SOUTHERN TRANSMISSION PROJECT ..................................................................................... 27

- General Description ......................................................................................................................... 27
- Operating Statistics .......................................................................................................................... 27
- Arrangements for Transmission Service from Adelanto Converter Station ................................... 28
- Permits, Licenses and Approvals ....................................................................................................... 28
**TABLE OF CONTENTS**
(Continued)

<table>
<thead>
<tr>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>CERTAIN FINANCIAL STATEMENTS RELATING TO THE PROJECT</td>
</tr>
<tr>
<td>THE PROJECT PARTICIPANTS</td>
</tr>
<tr>
<td>General</td>
</tr>
<tr>
<td>The Department</td>
</tr>
<tr>
<td>City of Anaheim</td>
</tr>
<tr>
<td>City of Riverside</td>
</tr>
<tr>
<td>DEVELOPMENTS IN THE CALIFORNIA ENERGY MARKETS</td>
</tr>
<tr>
<td>State Legislation</td>
</tr>
<tr>
<td>Future Regulation</td>
</tr>
<tr>
<td>Impact of Developments on the Project Participants</td>
</tr>
<tr>
<td>OTHER FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY</td>
</tr>
<tr>
<td>Federal Energy Legislation</td>
</tr>
<tr>
<td>Environmental Issues</td>
</tr>
<tr>
<td>Other Factors</td>
</tr>
<tr>
<td>CONSTITUTIONAL CHANGES IN CALIFORNIA</td>
</tr>
<tr>
<td>Proposition 218</td>
</tr>
<tr>
<td>Proposition 26</td>
</tr>
<tr>
<td>Other Initiatives</td>
</tr>
<tr>
<td>LITIGATION</td>
</tr>
<tr>
<td>TAX MATTERS</td>
</tr>
<tr>
<td>RATINGS</td>
</tr>
<tr>
<td>UNDERWRITING</td>
</tr>
<tr>
<td>FINANCIAL ADVISOR</td>
</tr>
<tr>
<td>CERTAIN LEGAL MATTERS</td>
</tr>
<tr>
<td>CERTAIN RELATIONSHIPS</td>
</tr>
<tr>
<td>VERIFICATION OF MATHEMATICAL COMPUTATIONS</td>
</tr>
<tr>
<td>CONTINUING DISCLOSURE UNDERTAKING FOR THE 2015 SERIES C SUBORDINATE BONDS</td>
</tr>
<tr>
<td>AVAILABLE INFORMATION</td>
</tr>
</tbody>
</table>

**APPENDIX A** – THE PROJECT PARTICIPANTS WITH THE LARGEST ENTITLEMENT SHARES | A-1 |
**APPENDIX B** – INTERMOUNTAIN POWER AGENCY AND INTERMOUNTAIN POWER PROJECT | B-1 |
**APPENDIX C** – SUMMARY OF CERTAIN DOCUMENTS | C-1 |
**APPENDIX D** – FORM OF CONTINUING DISCLOSURE RESOLUTION FOR THE 2015 SERIES C SUBORDINATE BONDS | D-1 |
**APPENDIX E** – PROPOSED FORM OF CO-BOND COUNSEL OPINION | E-1 |
**APPENDIX F** – ESTIMATED DEBT SERVICE REQUIREMENTS | F-1 |
Official Statement
relating to

$116,535,000
Southern California Public Power Authority
(a public entity organized under the laws of the State of California)
Transmission Project Revenue Bonds,
2015 Subordinate Refunding Series C
(Southern Transmission Project)

INTRODUCTION

Purpose; Authority for Issuance

This Official Statement (which includes the cover page, the table of contents and the appendices attached hereto) is furnished by the Southern California Public Power Authority (the “Authority”), a joint powers agency and a public entity organized under the laws of the State of California, to provide information concerning the Southern Transmission Project described herein and the $116,535,000 aggregate principal amount of the Authority’s Transmission Project Revenue Bonds, 2015 Subordinate Refunding Series C (the “2015 Series C Subordinate Bonds”). The 2015 Series C Subordinate Bonds are being issued pursuant to the provisions relating to the joint exercise of powers found in Chapter 5 of Division 7 of Title 1 of the Government Code of the State of California, as amended (the “Act”), and Article 11 of Chapter 3 of Part 1 of Division 2 of Title 5 of the Government Code of the State of California, and pursuant to an Indenture of Trust, dated as of March 1, 2015 (the “2015 Series C Subordinated Indenture”), from the Authority to U.S. Bank National Association, as trustee (the “Trustee”).

The 2015 Series C Subordinate Bonds are being issued to provide moneys to: (i) refund all of the Authority’s outstanding $125,005,000 Transmission Project Revenue Bonds, 2008 Subordinate Series B (the “Refunded Bonds”) issued pursuant to the Indenture of Trust, dated as of November 1, 2008 (the “2008 Series B Subordinated Indenture”), from the Authority to U.S. Bank National Association, as successor trustee; and (ii) pay the costs of issuance relating to the 2015 Series C Subordinate Bonds. See “THE AUTHORITY’S REFUNDING PLAN.”

Outstanding Bonds; Other Obligations

At the time of issuance of the 2015 Series C Subordinate Bonds, no senior lien bonds will be outstanding under the Indenture of Trust, dated as of May 1, 1983 (the “Original Indenture”), from the Authority to U.S. Bank National Association, as successor trustee (the “Senior Indenture Trustee”), as supplemented and amended (the “Senior Indenture”), including as supplemented and amended by the Twenty-Eighth Supplemental Indenture of Trust relating to the 2015 Series C Subordinate Bonds, dated as of March 1, 2015 (the “Twenty-Eighth Supplemental Indenture”). Any bonds issued by the Authority pursuant to the Act and the Senior Indenture are herein referred to as the “Senior Bonds.” Currently, the Authority has no Senior Bonds outstanding and no plans to issue Senior Bonds. All Senior Bonds were issued to finance or refinance payments-in-aid of construction for the Southern Transmission Project and the acquisition of the entitlements to the capability of the Southern Transmission Project from the Project Participants (as hereinafter defined). See “– Southern Transmission Project and Authority Capacity” below.
Upon the issuance of the 2015 Series C Subordinate Bonds and the defeasance of the Refunded Bonds, the Authority will have outstanding $544,190,000 aggregate principal amount of subordinate bonds payable on parity with the 2015 Series C Subordinate Bonds, as described below in this paragraph.

The Authority will have outstanding the following subordinate bonds: (i) $30,545,000 aggregate principal amount of Transmission Project Revenue Bonds, 1992 Subordinate Refunding Series A (the “1992 Subordinate Bonds”) issued under an Indenture of Trust, dated as of June 1, 1992 (the “1992 Subordinated Indenture”); (ii) $45,785,000 aggregate principal amount of Transmission Project Revenue Bonds, 2008 Subordinate Refunding Series A (the “2008 Series A Subordinate Bonds”) issued under an Indenture of Trust, dated as of January 1, 2008 (the “2008 Series A Subordinated Indenture”); (iii) $117,280,000 aggregate principal amount of Transmission Project Revenue Bonds, 2009 Subordinate Refunding Series A (the “2009 Subordinate Bonds”) issued under an Indenture of Trust, dated as of January 1, 2009 (the “2009 Subordinated Indenture”); (iv) $116,505,000 aggregate principal amount of Transmission Project Revenue Bonds, 2011 Subordinate Refunding Series A (the “2011 Subordinate Bonds”) issued under an Indenture of Trust, dated as of January 1, 2011 (the “2011 Subordinated Indenture”); (v) $39,245,000 aggregate principal amount of Transmission Project Revenue Bonds, 2012 Subordinate Refunding Series A (the “2012 Subordinate Bonds”) issued under an Indenture of Trust, dated as of February 1, 2012 (the “2012 Subordinated Indenture”); (vi) $65,120,000 aggregate principal amount of Transmission Project Revenue Bonds, 2013 Subordinate Refunding Series A and $16,145,000 aggregate principal amount of Transmission Project Revenue Bonds, 2013 Subordinate Refunding Series B (Federally Taxable) (collectively, the “2013 Subordinate Bonds”) issued under an Indenture of Trust, dated as of February 1, 2013 (the “2013 Subordinated Indenture”); and (vii) $84,640,000 aggregate principal amount of Transmission Project Revenue Bonds, 2015 Subordinate Refunding Series A and $28,925,000 aggregate principal amount of Transmission Project Revenue Bonds, 2015 Subordinate Refunding Series B (Federally Taxable) (collectively, the “2015 Series A and B Subordinate Bonds”), which are expected to be issued and delivered on March 4, 2015, issued under an Indenture of Trust, to be dated as of February 1, 2015 (the “2015 Series A and B Subordinated Indenture,” and together with the 1992 Subordinated Indenture, the 2008 Series A Subordinated Indenture, the 2009 Subordinated Indenture, the 2011 Subordinated Indenture, the 2012 Subordinated Indenture and the 2013 Subordinated Indenture, the “Prior Subordinated Indentures”).

The 1992 Subordinate Bonds, the 2008 Series A Subordinate Bonds, the 2009 Subordinate Bonds, the 2011 Subordinate Bonds, the 2012 Subordinate Bonds, the 2013 Subordinate Bonds and the 2015 Series A and B Subordinate Bonds (collectively, the “Prior Subordinate Bonds”) were issued primarily to refund certain bonds previously issued under the Senior Indenture and certain of the Prior Subordinated Indentures or other prior subordinated indentures that have been discharged and to fund certain related costs.

Security and Sources of Payment for the Subordinate Bonds; Other Obligations

The Prior Subordinate Bonds are payable from certain moneys available from time to time in the General Reserve Fund under the Senior Indenture that are transferred to funds held under the Prior Subordinated Indentures. Similarly, principal of, premium, if any, and interest on the 2015 Series C Subordinate Bonds will be payable from certain moneys in the General Reserve Fund under the Senior Indenture that are transferred to funds held under the 2015 Series C Subordinated Indenture. Moneys so transferred to meet the requirements of the 2015 Series C Subordinated Indenture and the Prior Subordinated Indentures will be transferred in a manner such that none will have priority over any other moneys so transferred. As a result, none of the series of Prior Subordinate Bonds will have priority over or otherwise rank prior to any other series of Prior Subordinate Bonds or the 2015 Series C Subordinate Bonds. The 2015 Series C Subordinate Bonds and the Prior Subordinate Bonds are collectively referred to herein as the “Subordinate Bonds.” See “SECURITY AND SOURCES OF PAYMENT FOR THE SENIOR BONDS AND THE SUBORDINATE BONDS – Flow of Funds.”
In addition to the Subordinate Bonds, Senior Bonds, as well as additional subordinate bonds that rank on a parity with the Subordinate Bonds, may be issued by the Authority. Further, interest rate swap agreements and certain other types of agreements (“Parity Swaps”) payable on a parity with the 2015 Series C Subordinate Bonds (other than with respect to termination payments thereunder, which shall be payable on a basis subordinate and junior to the 2015 Series C Subordinate Bonds) may be entered into by the Trustee, the Authority and the provider of any such agreement. See “SUMMARY OF CERTAIN DOCUMENTS – SUMMARY OF CERTAIN PROVISIONS OF THE SENIOR INDENTURE – Application of Revenues” and “– SUMMARY OF CERTAIN PROVISIONS OF THE 2015 SERIES C SUBORDINATED INDENTURE – Application of Pledged Revenues” in Appendix C.

**The Authority**

The Authority, the membership of which is comprised of 11 cities and one irrigation district of the State of California, was formed pursuant to the Act and the Joint Powers Agreement, dated as of November 1, 1980 (the Joint Powers Agreement as amended to the date hereof being hereinafter referred to as the “Joint Powers Agreement”). See “SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY – Formation.” Certain duties and responsibilities of the Authority arising in connection with the Southern Transmission Project are and will be performed by the Department of Water and Power of The City of Los Angeles (the “Department”) pursuant to the Agency Agreement, dated as of May 1, 1983 (the “Agency Agreement”). See “SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY – Organization and Management.”

**Southern Transmission Project and Authority Capacity**

The Senior Bonds were issued by the Authority for the purpose of financing or refinancing (i) payments-in-aid of construction made to the Intermountain Power Agency, a political subdivision of the State of Utah (“IPA”), for application to costs of acquisition and construction of a +500-kV DC bi-pole transmission line from a coal-fired, steam-electric generation station and switchyard located near Lynndyl, in Millard County, Utah, to Adelanto, California, 488 miles in length, together with an AC/DC converter station at each end and related microwave communication system facilities (the “Southern Transmission Project”), and (ii) the acquisition of the entitlements to the capability of the Southern Transmission Project (“Authority Capacity”) from the Department and the California cities of Anaheim, Riverside, Pasadena, Burbank and Glendale (which, together with the Department, are hereinafter collectively referred to as the “Project Participants”). As a result of upgrades completed in December 2010 (the “STS Upgrade Project”), which were financed with proceeds of the Refunded Bonds, the capacity of the Southern Transmission Project is now 2,400 MW (an increase from its prior rating of 1,920 MW). For selected information with respect to the largest of the Project Participants (i.e., the Department and the California cities of Anaheim and Riverside), see “THE PROJECT PARTICIPANTS WITH THE LARGEST ENTITLEMENT SHARES” in Appendix A hereto.

**Intermountain Power Project**

IPA has constructed and placed in commercial operation the Intermountain Power Project (hereinafter, “IPP”) which consists of: (a) a two-unit, coal-fired, steam-electric generating plant with a net rating of 1,685 MW, with a reduction in the net rating to 1,665 MW as needed due to weather during June through September, and a switchyard located near Lynndyl, Utah; (b) two 50-mile 345-kv AC transmission lines from such switchyard to the Mona switchyard near Mona, Utah and a 144-mile 230-kv AC transmission line from such switchyard to the Gonder switchyard near Ely, Nevada; (c) the Southern Transmission Project; (d) a railcar service center; and (e) certain water rights and coal supplies. See “INTERMOUNTAIN POWER AGENCY AND INTERMOUNTAIN POWER PROJECT – INTERMOUNTAIN POWER PROJECT” in Appendix B hereto for a more detailed description of IPP. See also “THE DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES – THE
POWER SYSTEM – Jointly-Owned Generating Units and Contracted Capacity Rights in Generating Units – Intermountain Power Project – Intermountain Generating Station upon the termination of the IPP Contract” in Appendix A hereto with respect to the possible future replacement of the IPP coal-fired units with combined cycle natural gas-fired units.

Each Project Participant has entered into a power sales contract, as amended, with IPA obligating such Project Participant to purchase the share of IPP capacity and energy stated therein (each, an “IPP Power Sales Contract”). The IPP Power Sales Contracts obligate the Project Participants to pay their respective percentage shares of the costs of IPP on a “take-or-pay” basis. The IPP Power Sales Contracts provide that the Project Participants, or an entity on their behalf, may make payments-in-aid of construction for the Southern Transmission Project. See “SUMMARY OF CERTAIN PROVISIONS OF THE IPP POWER SALES CONTRACTS” in Appendix C hereto.

Certain Project Participants (i.e., the Department and the California cities of Burbank and Pasadena) are also project participants in the Authority’s Milford Wind Corridor Phase I Project (the “Milford Phase I Project”) and utilize their IPP capacity rights, under agreements relating to the IPP, to receive energy delivered from the Milford Phase I Project over the Southern Transmission System to the Adelanto Converter Station in California. Additionally, certain Project Participants (i.e., the Department and the California city of Glendale) are also project participants in the Authority’s Milford Wind Corridor Phase II Project (the “Milford Phase II Project”) and utilize their IPP capacity rights, under agreements relating to the IPP, to receive energy delivered from the Milford Phase II Project over the Southern Transmission System to the Adelanto Converter Station in California. See “SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY – Other Activities of the Authority – Milford Wind Corridor Phase I Project” and “– Milford Wind Corridor Phase II Project.”

For a discussion of litigation relating to IPA, see “LITIGATION.”

Payments-In-Aid of Construction

Pursuant to the Southern Transmission System Agreement, dated as of May 1, 1983, as amended by the First Amendment to the STS Agreement, dated as of November 1, 2008, between the Authority and IPA (as amended, the “STS Agreement”), the Authority agreed to make payments-in-aid of construction to IPA for all costs of acquisition and construction of the Southern Transmission Project, including the STS Upgrade Project. To the extent that payments-in-aid of construction were made and applied to the costs of acquisition and construction of the Southern Transmission Project, and IPA was not required to issue its bonds, notes or other evidences of indebtedness for such purpose, the Project Participants’ payment obligations under their respective IPP Power Sales Contracts have been reduced. See “SUMMARY OF CERTAIN PROVISIONS OF THE SOUTHERN TRANSMISSION SYSTEM AGREEMENT” in Appendix C hereto.

Acquisition of Authority Capacity

The Authority and each Project Participant have entered into an Agreement for the Acquisition of Capacity, dated as of May 1, 1983 (collectively, the “Capacity Acquisition Agreements”), pursuant to which each Project Participant has assigned its entitlement to capacity of the Southern Transmission Project as set forth in its respective IPP Power Sales Contract to the Authority in return for the Authority’s agreement to make payments-in-aid of construction pursuant to the STS Agreement.

Transmission Service

The Authority and each Project Participant have also entered into a Transmission Service Contract, dated as of May 1, 1983 (collectively, the “Transmission Service Contracts”). Under the
Transmission Service Contracts, the Project Participants are entitled to transmission service utilizing Authority Capacity to the extent of their respective Transmission Service Shares as set forth below, and the Project Participants are obligated to make payments therefor on a “take-or-pay” basis, that is, whether or not the Southern Transmission Project or any part thereof has been completed, is operating or is operable, or its service is suspended, interfered with, reduced or curtailed or terminated in whole or in part. The payment obligations under the Transmission Service Contracts constitute operating expenses of the respective Project Participants, payable solely from their respective electric system revenues. As operating expenses of their respective electric systems, the payment obligations of the Department under its Transmission Service Contract and all other of its “take-or-pay” contract obligations are payable on a parity with the Department’s electric system revenue bonds (see “THE PROJECT PARTICIPANTS WITH THE LARGEST ENTITLEMENT SHARES” in Appendix A hereto) and the payment obligations of the other Project Participants under their respective Transmission Service Contracts and all other of their “take-or-pay” contract obligations are payable prior to the payment of debt service on the revenue bonds of their electric systems. A failure by a Project Participant to make payments when due under its Transmission Service Contract likely would result in larger payments needing to be made by the other Project Participants. See “SECURITY AND SOURCES OF PAYMENT FOR THE SENIOR BONDS AND THE SUBORDINATE BONDS – Transmission Service Contracts” herein and “SUMMARY OF CERTAIN PROVISIONS OF THE TRANSMISSION SERVICE CONTRACTS” in Appendix C hereto.

The following table sets forth the Transmission Service Shares of each of the Project Participants with respect to Authority Capacity.

<table>
<thead>
<tr>
<th>Project Participants</th>
<th>Transmission Service Share</th>
</tr>
</thead>
<tbody>
<tr>
<td>Department of Water and Power of Los Angeles</td>
<td>59.534%</td>
</tr>
<tr>
<td>City of Anaheim</td>
<td>17.647</td>
</tr>
<tr>
<td>City of Riverside</td>
<td>10.164</td>
</tr>
<tr>
<td>City of Pasadena</td>
<td>5.883</td>
</tr>
<tr>
<td>City of Burbank</td>
<td>4.498</td>
</tr>
<tr>
<td>City of Glendale</td>
<td>2.274</td>
</tr>
<tr>
<td>Total</td>
<td>100.000%</td>
</tr>
</tbody>
</table>

Continuing Disclosure Undertaking

Pursuant to a resolution of the Authority’s Board of Directors adopted on February 19, 2015 (the “Continuing Disclosure Resolution”), the Authority has agreed for the benefit of the registered owner and the “Beneficial Owners” (as defined in the Continuing Disclosure Resolution) of the 2015 Series C Subordinate Bonds to provide certain financial information and operating data and to provide notices of certain events. See “CONTINUING DISCLOSURE UNDERTAKING FOR THE 2015 SERIES C SUBORDINATE BONDS.”

Certain Information; Summaries and References to Documents

In preparing this Official Statement, the Authority has relied upon information relating to the Southern Transmission Project provided to the Authority by the Department and information relating to certain of the Project Participants furnished to the Authority by such Project Participants. This Official Statement also includes summaries of the terms of the 2015 Series C Subordinate Bonds, the 2015 Series C Subordinated Indenture, the Senior Indenture, the Transmission Service Contracts, the STS Agreement, the IPP Power Sales Contracts, the Capacity Acquisition Agreements, and certain contracts and other arrangements. The summaries of and references to all documents, contracts, 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 such document, statute, report or instrument. Capitalized terms not defined herein shall have the meanings set forth in the respective documents.

THE AUTHORITY’S REFUNDING PLAN

The proceeds of the 2015 Series C Subordinate Bonds, together with certain other available moneys, will provide funds to refund the Refunded Bonds. The Refunded Bonds are expected to be redeemed on July 1, 2018 (the “Redemption Date”) in the principal amount of $125,005,000. The Refunded Bonds are described in the table below.

<table>
<thead>
<tr>
<th>Refunded Bonds</th>
<th>Maturity Date (June 1)</th>
<th>Outstanding Principal Amount</th>
<th>Interest Rate</th>
<th>CUSIP</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2024</td>
<td>$18,465,000</td>
<td>5.75%</td>
<td>842477RL7</td>
</tr>
<tr>
<td></td>
<td>2025</td>
<td>40,425,000</td>
<td>6.00</td>
<td>842477RM5</td>
</tr>
<tr>
<td></td>
<td>2027</td>
<td>66,115,000</td>
<td>6.00</td>
<td>842477RN3</td>
</tr>
</tbody>
</table>

The refunding of the Refunded Bonds will be effected by depositing proceeds of the 2015 Series C Subordinate Bonds and certain other moneys provided by the Authority in an escrow fund (the “Escrow Fund”). The moneys in the Escrow Fund are expected to be applied to the purchase of non-callable, direct obligations of, or obligations fully and unconditionally guaranteed as to timely payment of principal and interest by, the United State of America (the “Defeasance Obligations”) or to be held as cash. The Defeasance Obligations will bear interest at such rates and will be scheduled to mature at such times and in such amounts so that, when paid in accordance with their terms, such amounts, together with any amounts held as cash in the Escrow Fund, will provide sufficient available moneys to pay interest on the Refunded Bonds as the same shall become due on and before July 1, 2018, and to pay the redemption price (i.e., 100% of the principal amount) of such Refunded Bonds on July 1, 2018, the date of redemption therefor. The Escrow Fund will be held by the Trustee, as trustee for the Refunded Bonds, in irrevocable trust and used solely for the payment of the interest on and redemption price of the Refunded Bonds, subject only to the payment to the Authority, in accordance with the Twenty-Eighth Supplemental Indenture of any cash not required for such purpose.

Upon such deposit and investment and compliance with certain notice requirements set forth in the 2008 Series B Subordinated Indenture, the liability of the Authority with respect to the Refunded Bonds will cease and the Refunded Bonds will no longer be outstanding under the 2008 Series B Subordinated Indenture, except that the Owners of the Refunded Bonds will be entitled to payment thereof solely from the amounts on deposit in the Escrow Fund.

On the date of delivery of the 2015 Series C Subordinate Bonds, the Authority will receive a report from Samuel Klein and Company, an independent arbitrage consultant, verifying (i) the adequacy of the principal amounts of the Defeasance Obligations on deposit in the Escrow Fund together with certain other available amounts, if any, and interest income earned on such Defeasance Obligations, to pay interest on the Refunded Bonds as the same shall become due on and prior to July 1, 2018 and to pay on July 1, 2018, the redemption date of the Refunded Bonds, the redemption price for such Refunded Bonds and (ii) the mathematical computations of the yield on the 2015 Series C Subordinate Bonds and the yield on the Defeasance Obligations purchased with a portion of the proceeds of the sale of the 2015 Series C Subordinate Bonds and other available funds of the Authority. See “VERIFICATION OF MATHEMATICAL COMPUTATIONS.”
ESTIMATED SOURCES AND USES OF FUNDS

The estimated sources and uses of funds relating to the 2015 Series C Subordinate Bonds are shown below:

Sources:

<table>
<thead>
<tr>
<th>Description</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>Principal Amount</td>
<td>$116,535,000</td>
</tr>
<tr>
<td>Bond Premium</td>
<td>25,700,952</td>
</tr>
<tr>
<td>Transfer from the Construction Fund(1)</td>
<td>4,490,991</td>
</tr>
<tr>
<td><strong>Total Sources</strong></td>
<td><strong>$146,726,943</strong></td>
</tr>
</tbody>
</table>

Uses:

<table>
<thead>
<tr>
<th>Description</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>Deposit to Escrow Fund</td>
<td>$146,130,176</td>
</tr>
<tr>
<td>Costs of Issuance(2)</td>
<td>596,767</td>
</tr>
<tr>
<td><strong>Total Uses</strong></td>
<td><strong>$146,726,943</strong></td>
</tr>
</tbody>
</table>

(1) Unused proceeds of the Refunded Bonds.
(2) Includes, among other things, Underwriters’ discount, Trustee and Paying Agent fees, Co-Bond Counsel fees, Underwriters’ counsel fees, rating agency’s fees, Financial Advisor fees, printing costs and other miscellaneous expenses.

ESTIMATED DEBT SERVICE REQUIREMENTS

The estimated debt service requirements for the Prior Subordinate Bonds and the 2015 Series C Subordinate Bonds (immediately following the issuance of the 2015 Series C Subordinate Bonds and the refunding of the Refunded Bonds) are set forth in Appendix F.

DESCRIPTION OF THE 2015 SERIES C SUBORDINATE BONDS

General

The 2015 Series C Subordinate Bonds will be issued in the aggregate principal amount indicated on the cover page of this Official Statement, will be dated their date of delivery, and will bear interest at the rates per annum and will mature on July 1 in the years and in the principal amounts set forth on the inside cover page of this Official Statement. The 2015 Series C Subordinate Bonds will be issued as fully registered bonds in the denomination of $5,000 principal amount and any integral multiple thereof. Interest on the 2015 Series C Subordinate Bonds will be payable semiannually on January 1 and July 1 of each year, commencing July 1, 2015, and will be calculated on the basis of a 360-day year consisting of twelve 30-day months.

The 2015 Series C Subordinate Bonds when initially issued will be registered in the name of Cede & Co., as registered owner and nominee of The Depository Trust Company, New York, New York (“DTC”). So long as DTC, or its nominee Cede & Co., is the registered owner of the 2015 Series C Subordinate Bonds, all payments of principal of, premium, if any, and interest on such 2015 Series C Subordinate Bonds will be made directly to DTC. Disbursement of such payments to the DTC Participants (as defined below) will be the responsibility of DTC. Disbursement of such payments to the applicable Beneficial Owners (as defined below) of the 2015 Series C Subordinate Bonds will be the responsibility of the DTC Participants as more fully described herein. See “BOOK-ENTRY ONLY SYSTEM” below.

Redemption Provisions

Optional Redemption. The 2015 Series C Subordinate Bonds maturing on July 1, 2024 are not subject to optional redemption prior to maturity. The 2015 Series C Subordinate Bonds maturing on and
after July 1, 2025 are subject to redemption prior to maturity at the option of the Authority on and after January 1, 2025, in whole or in part at any time, at par (without premium), plus accrued interest to the date of redemption.

**Selection of 2015 Series C Subordinate Bonds to be Redeemed.** The Authority shall select the maturity or maturities of 2015 Series C Subordinate Bonds to be redeemed. If less than all of the 2015 Series C Subordinate Bonds of like maturity shall be called for prior redemption, the particular 2015 Series C Subordinate Bonds or portions of 2015 Series C Subordinate Bonds to be redeemed shall be selected by the Trustee by lot or in such other manner as the Trustee in its discretion may deem appropriate; provided, however, that the portion of any 2015 Series C Subordinate Bond to be redeemed will be in the principal amount of an authorized denomination.

**Notice of Redemption.** The 2015 Series C Subordinated Indenture requires the Trustee to give notice of any redemption of the 2015 Series C Subordinate Bonds by mail not less than 30 nor more than 60 days prior to the redemption date. If the date of mailing of notice of any optional redemption the Authority has not deposited with the Trustee moneys sufficient to redeem all the 2015 Series C Subordinate Bonds called for redemption, such notice will state that it is subject to the availability of funds for such purpose and will be of no effect unless funds sufficient for such purpose are available. Failure to mail notice, or any defect in such mailed notice, however, with respect to any particular 2015 Series C Subordinate Bond will not affect the validity of the proceedings for the redemption of such 2015 Series C Subordinate Bond.

**Effect of Redemption.** Notice having been given in the manner provided in the 2015 Series C Subordinated Indenture, the 2015 Series C Subordinate Bonds or portions thereof so called for redemption shall become due and payable on the redemption date so designated at the redemption price, plus interest accrued and unpaid to the redemption date, and, upon presentation and surrender thereof at the office specified in such notice, such 2015 Series C Subordinate Bonds, or portions thereof (accompanied by CUSIP number identification), shall be paid at the redemption price, plus interest accrued and unpaid to the redemption date. If, on the redemption date, moneys for the redemption of all the 2015 Series C Subordinate Bonds or portions thereof to be redeemed, together with interest to the redemption date, shall be held by the Trustee so as to be available therefor on said date and if notice of redemption shall have been given as aforesaid, then, from and after such redemption date interest on the 2015 Series C Subordinate Bonds or portions thereof so called for redemption shall cease to accrue and become payable. If said moneys shall not be so available on the redemption date, such 2015 Series C Subordinate Bonds or portions thereof shall continue to remain outstanding under the 2015 Subordinated Indenture and bear interest.

**BOOK-ENTRY ONLY SYSTEM**

**General**

DTC will act as securities depository for the 2015 Series C Subordinate Bonds. The 2015 Series C Subordinate Bonds will be issued as fully-registered securities registered in the name of Cede & Co. (DTC’s partnership nominee) or such other name as may be requested by an authorized representative of DTC. One fully-registered 2015 Series C Subordinate Bond will be issued for each maturity of the 2015 Series C Subordinate Bonds, each in the aggregate principal amount of such maturity, and will be deposited with DTC.

DTC, the world’s largest securities depository, is a limited-purpose trust company organized under the New York Banking Law, a “banking organization” within the meaning of the New York Banking Law, a member of the Federal Reserve System, a “clearing corporation” within the meaning of the New York Uniform Commercial Code, and a “clearing agency” registered pursuant to the provisions...
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 DTC’s participants are on file with the Securities and Exchange Commission. More information about DTC can be found at www.dtcc.com. The information on such website is not incorporated herein by reference.

Purchases of the 2015 Series C Subordinate Bonds under the DTC book-entry system must be made by or through Direct Participants, which will receive a credit for the 2015 Series C Subordinate Bonds on DTC’s records. The ownership interest of each actual purchaser of each 2015 Series C Subordinate Bonds (“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 2015 Series C Subordinate 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 2015 Series C Subordinate Bonds, except in the event that use of the book-entry system for the 2015 Series C Subordinate Bonds is discontinued.

To facilitate subsequent transfers, all 2015 Series C Subordinate 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 2015 Series C Subordinate 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 2015 Series C Subordinate Bonds. DTC’s records reflect only the identity of the Direct Participants to whose accounts such 2015 Series C Subordinate 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 2015 Series C Subordinate Bonds may wish to take certain steps to augment the transmission to them of notices of significant events with respect to the 2015 Series C Subordinate Bonds, such as redemptions (if applicable), defaults and proposed amendments to the 2015 Series C Subordinated Indenture. For example, Beneficial Owners of 2015 Series C Subordinate Bonds may wish to ascertain that the nominee holding the 2015 Series C Subordinate 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 bond registrar and request that copies of notices be provided directly to them.

Redemption notices (if applicable) shall be sent to DTC. If less than all of the 2015 Series C Subordinate Bonds of a maturity are being redeemed, DTC’s practice is to determine by lot the amount of the interest of each Direct Participant in such maturity to be redeemed.

Neither DTC nor Cede & Co. (nor such other DTC nominee) will consent or vote with respect to 2015 Series C Subordinate Bonds unless authorized by a Direct Participant in accordance with DTC’s MMI Procedures. Under its usual procedures, DTC mails an Omnibus Proxy to the Authority 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 2015 Series C Subordinate Bonds are credited on the record date (identified in a listing attached to the Omnibus Proxy).

Principal, redemption price (if applicable) and interest payments on the 2015 Series C Subordinate 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 the Authority or the Trustee, on each payment date in accordance with their respective holdings shown on DTC’s records. Payments by Direct and 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 the Authority, subject to any statutory or regulatory requirements as may be in effect from time to time. Payment of principal, redemption price (if applicable) and interest to Cede & Co. (or such other nominee as may be requested by an authorized representative of DTC) is the responsibility of the Authority or the Trustee, disbursement of such payments to Direct Participants will be the responsibility of DTC, and disbursement of such payments to Beneficial Owners is the responsibility of Direct and Indirect Participants.

DTC may discontinue providing its services as securities depository with respect to the 2015 Series C Subordinate Bonds at any time by giving reasonable notice to the Authority or the Trustee. Under such circumstances, in the event that a successor depository is not obtained, definitive 2015 Series C Subordinate Bonds are required to be printed and delivered.

The Authority may decide to discontinue use of the system of book-entry transfers through DTC (or a successor securities depository). In that event, definitive 2015 Series C Subordinate Bonds will be printed and delivered.

The foregoing description concerning DTC and DTC’s book-entry system is based solely on information furnished by DTC. No representation is made herein by the Authority or the Underwriters as to the accuracy or completeness of such information, and the Authority and the Underwriters take no responsibility for the accuracy or completeness thereof.

Discontinuation of the Book-Entry Only System

If DTC determines not to continue to act as securities depository by giving notice to the Authority and the Trustee, and discharges its responsibilities with respect thereto under applicable law and there is not a successor securities depository, or the Authority determines not to continue the book-entry system through a securities depository, the Authority and the Trustee will cause the delivery of definitive 2015 Series C Subordinate Bonds to the Beneficial Owners of the 2015 Series C Subordinate Bonds registered in the names of such Beneficial Owners as shall be specified to the Trustee by DTC.
If the book-entry system is discontinued the following provisions would apply: (i) the principal and redemption price (if applicable) of the 2015 Series C Subordinate Bonds will be payable upon surrender of such 2015 Series C Subordinate Bond at the principal corporate trust office of the Trustee (as paying agent for the 2015 Series C Subordinate Bonds) and at the office of any other paying agent hereafter appointed by the Authority; (ii) interest on the 2015 Series C Subordinate Bonds will be payable by check of the Trustee mailed by first-class mail, postage prepaid, on the applicable interest payment date to the Owner thereof at his or her address shown on the registration books maintained by the Trustee as of the 15th day of the calendar month immediately preceding such interest payment date (the “Record Date”) or in immediately available funds by wire transfer on the interest payment date to a designated account, if payable to any Owner of a 2015 Series C Subordinate Bond or Bonds in an aggregate principal amount of $1,000,000 or more, upon written request of such Owner to the Trustee received by the Trustee prior to the Record Date for the first interest payment date as to which such request shall be effective, specifying the account or accounts to which such payment shall be made (which request shall remain in effect until revoked or reversed by such Owner in a subsequent writing delivered to the Trustee); (iii) the transfer of any 2015 Series C Subordinate Bond shall be registrable only upon the books of the Authority, which shall be kept for such purposes at the principal corporate trust office of the Trustee, as bond registrar, by the Owner thereof in person or by his or her attorney duly authorized in writing, upon surrender of such 2015 Series C Subordinate Bond, together with a written instrument of transfer satisfactory to the bond registrar duly executed by the Owner or his or her duly authorized attorney, and upon payment by such Owner of any charges which the Authority or the Trustee may impose to reimburse it for any tax, fee or other governmental charge required to be paid with respect to such registration of transfer; (iv) 2015 Series C Subordinate Bonds may be exchanged for an equal aggregate principal amount of 2015 Series C Subordinate Bonds of the same tenor, Series, maturity and interest rate in such other authorized denomination or denominations as shall be requested by such Owner, upon surrender of such 2015 Series C Subordinate Bonds at the principal corporate trust office of the Trustee, as bond registrar, and upon payment by such Owner of any charges which the Authority or the Trustee may impose to reimburse it for any tax, fee or other governmental charge required to be paid with respect to such exchange; and (v) the Trustee (as bond registrar for the 2015 Series C Subordinate Bonds) will not be required to register the transfer of, or exchange, any 2015 Series C Subordinate Bonds called for redemption (if applicable), or any 2015 Series C Subordinate Bonds during the period of 15 days next preceding any selection of 2015 Series C Subordinate Bonds to be redeemed (if applicable).

SECURITY AND SOURCES OF PAYMENT FOR THE SENIOR BONDS AND THE SUBORDINATE BONDS

Pledge Effected by the Senior Indenture

The Senior Indenture provides that the Senior Bonds, if any, are special, limited obligations of the Authority payable solely from and secured solely by, Revenues and all funds established by the Senior Indenture, including the investments, if any, thereof and the same are pledged and assigned to the Senior Indenture Trustee, for the benefit of the holders of the Senior Bonds (the “Senior Bondholders”), subject only to the provisions of the Senior Indenture permitting the application thereof for the purposes and on the terms and conditions set forth in the Senior Indenture. Currently, no Senior Bonds are outstanding and the Authority currently has no plans to issue Senior Bonds. For the definition of “Revenues” as used in the preceding sentence, see “– Flow of Funds” below. The Senior Indenture also provides that the Senior Indenture will remain outstanding for so long as any Senior Bonds, Subordinate Bonds (including the 2015 Series C Subordinate Bonds) or Notes of the Authority with respect to the Southern Transmission Project remain outstanding.

See “SUMMARY OF CERTAIN PROVISIONS OF THE SENIOR INDENTURE” in Appendix C hereto for further discussion of certain of the terms and provisions of the Senior Indenture.
Pledge Effected by the 2015 Series C Subordinated Indenture

The 2015 Series C Subordinate Bonds and the Prior Subordinate Bonds are payable without priority on the basis of their respective debt service requirements from Available Revenues transferred from the General Reserve Fund of the Senior Indenture to the 2015 Series C Subordinated Indenture and the Prior Subordinated Indentures, respectively. As a result, no series of Subordinate Bonds will have priority over or otherwise rank prior to any other series of Subordinate Bonds.

The availability of Available Revenues (defined below) is subject to prior payment of all amounts payable in connection with any Senior Bonds and amounts payable from the General Reserve Fund. See “— Flow of Funds” below.

The 2015 Series C Subordinated Indenture provides that the Authority has pledged and assigned to the Trustee, for the benefit of the Owners of the 2015 Series C Subordinate Bonds and any Parity Swap Providers, (i) the Pledged Revenues and (ii) the 2015 Series C Issue Fund and all Accounts therein established by the 2015 Series C Subordinated Indenture, subject only to the provisions of the 2015 Series C Subordinated Indenture and the Twenty-Eighth Supplemental Indenture permitting the application thereof for the purposes and on the terms and conditions set forth in the 2015 Series C Subordinated Indenture and the Twenty-Eighth Supplemental Indenture. Upon delivery, the 2015 Series C Subordinate Bonds shall be special, limited obligations of the Authority payable solely from and secured as to the payment of the principal or redemption price, if applicable, thereof and interest thereon, in accordance with their terms and the provisions of the 2015 Series C Subordinated Indenture and the Twenty-Eighth Supplemental Indenture, solely by the moneys, Fund and Accounts set forth in clauses (i) and (ii) of this paragraph.

“Pledged Revenues” with respect to the 2015 Series C Subordinate Bonds are all Available Revenues transferred to and deposited in the 2015 Series C Pledged Revenues Account pursuant to the Senior Indenture (including the Twenty-Eighth Supplemental Indenture).

“Available Revenues” are all moneys and funds at any time on deposit in the General Reserve Fund established by the Senior Indenture and not required to meet a deficiency under the Senior Indenture or required by the Senior Indenture to be used for payment, purchase or redemption of Senior Bonds.

See also “SUMMARY OF CERTAIN PROVISIONS OF THE 2015 SERIES C SUBORDINATED INDENTURE” in Appendix C hereto for further discussion of certain of the terms and provisions of the 2015 Series C Subordinated Indenture.

General Limitation on Obligations

The 2015 Series C Subordinate Bonds are not obligations of the State of California, any public agency thereof (other than the Authority), any member of the Authority or the Project Participants, and neither the faith and credit nor the taxing power of any of the foregoing (including the Authority) is pledged for the payment of any of the 2015 Series C Subordinate Bonds. The 2015 Series C Subordinate Bonds shall not constitute debt or indebtedness of the Authority within the meaning of any provision or limitation of the Constitution or statutes of the State of California, and shall not constitute nor give rise to a pecuniary liability of the Authority or a charge against its general credit. The Authority has no taxing power.

Transmission Service Contracts

Each Transmission Service Contract constitutes an obligation of the respective parties until the terms of all of the Transmission Service Contracts expire on June 15, 2027 or such later date as all bonds
and the interest thereon shall have been paid in full or adequate provision for such payment shall have been made. The payment obligations under the Transmission Service Contracts constitute a cost of transmission service and an operating expense of the respective Project Participants, payable solely from their electric system revenues. As operating expenses of their respective electric systems, the payment obligations of the Department under its Transmission Service Contract and all other of its “take-or-pay” contract obligations are payable on a parity with the Department’s electric system revenue bonds, and the payment obligations of the other Project Participants under their respective Transmission Service Contracts and all other of their “take-or-pay” contract obligations are payable prior to the payment of debt service on the revenue bonds of their electric systems.

Each Project Participant has covenanted in its Transmission Service Contract to establish, maintain and collect rates and charges for the electric service it furnishes sufficient to provide revenues which, together with its available electric system reserves, are adequate to enable it to pay the Authority all amounts payable under its Transmission Service Contract and to pay all other amounts payable from, and all liens on and lawful charges against, its electric system revenues.

Payments are to be made by the Project Participants on a “take-or-pay” basis, that is, whether or not the Southern Transmission Project or any part thereof has been completed, is operating or operable, or its service is suspended, interfered with, reduced or curtailed or terminated in whole or in part, and such payments shall not be subject to reduction whether by offset or otherwise and shall not be conditional upon the performance or nonperformance by any party of any agreement for any cause whatsoever.

A failure of a Project Participant to make payments when due under its Transmission Service Contract is likely to result in larger payments needing to be made by the other Project Participants in subsequent periods for the purpose of enabling the Authority to pay operating expenses, debt service and other costs of the acquisition of Authority Capacity and to maintain any required reserves therefor. To the extent the amount to be paid by the nonpaying Project Participant is not offset by revenues from sales of transmission service derived by the Authority in respect of such non-paying Project Participant’s Transmission Service Share or from any required reserves, such non-payment may result in deficits in funds under the Senior Indenture, the Prior Subordinated Indentures and the 2015 Series C Subordinated Indenture. In such event, the Authority would be required, in accordance with the Transmission Service Contracts, the Senior Indenture, the Prior Subordinated Indentures and the 2015 Series C Subordinated Indenture, to amend the Annual Budget to provide increases in subsequent billings to all Project Participants based upon Transmission Service Shares, including the non-paying Project Participant, equal to the amount of such deficiency. Such increased billings are not conditioned upon any transfer of the non-paying Project Participant’s Transmission Service Share to the other Project Participants. Amounts thereafter collected from such non-paying Project Participant are to be credited against the next billing of such other Project Participants as shall be appropriate.

The Transmission Service Contracts provide that the obligations of the Project Participants under the respective Transmission Service Contracts are several and not joint. During each Transmission Service Year, each Project Participant is obligated to pay its share of Monthly Transmission Costs, which consist of all of the Authority’s costs resulting from the acquisition, financing and refinancing of Authority Capacity, to the extent not paid from the proceeds of the Senior Bonds or from Notes or other evidences of indebtedness issued in anticipation of the issuance of such Senior Bonds. Pursuant to the Transmission Service Contracts, such Monthly Transmission Costs are to be billed by the Authority to the Project Participants by the tenth calendar day of each month for the then current month based on the estimates contained in the Annual Budget prepared by the Authority prior to the beginning of each Transmission Service Year, as such Annual Budget may be amended during such year, and are to be paid by the Project Participants on or before ten days after receipt of such billing statement therefor. Such Monthly Transmission Costs include, without limitation:
(1) Monthly Power Costs (as defined in the IPP Power Sales Contracts) allocable to the Southern Transmission Project;

(2) The amounts which the Senior Indenture requires the Authority to pay or deposit during such month into funds or accounts for debt service on the Senior Bonds or reserve requirements for the Senior Bonds; and the payment of interest on Notes or other evidences of indebtedness issued in anticipation of the issuance of Senior Bonds; and

(3) One-twelfth of: the amount which the Authority is required under the Senior Indenture to pay or deposit during the then current Transmission Service Year into any other fund or account established by the Senior Indenture, including any amount needed to eliminate a deficiency in any such fund established under the Senior Indenture whether or not resulting from a default in payments by any Project Participant of amounts due under any Transmission Service Contract; the costs of providing transmission service during the then current Transmission Service Year; and the amount necessary during the then current Transmission Service Year to pay or provide reserves for all taxes which the Authority is required to pay with respect to Authority Capacity.

Additionally, the Authority is required to make provision in the Annual Budget for each Fiscal Year for all amounts required under the 2015 Series C Subordinated Indenture to be deposited into the 2015 Series C Issue Fund (including particularly the amounts required for payment of 2015 Series C Accrued Debt Service) and for all amounts required under each Prior Subordinated Indenture to be deposited into each Issue Fund established for such series of Prior Subordinate Bonds, including particularly the amounts required for payment of Accrued Debt Service for each such series, and (without duplication) any other amounts payable under the interest rate swap agreements so that the respective Payment Accounts, the Reserve Accounts, if any, and the Charges Accounts for each series shall be maintained at the respective required balances.

The Senior Indenture, the Prior Subordinated Indentures and the 2015 Series C Subordinated Indenture require the Authority, quarterly, to review its estimates set forth in the then current Annual Budget and in the event such estimates do not substantially correspond with actual revenues, expenses or other requirements, to adopt an amended Annual Budget for the remainder of the Fiscal Year. The Authority 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 related to Authority Capacity.

The amount of Monthly Transmission Costs to be paid by each Project Participant for any month shall be its Transmission Service Share times the Monthly Transmission Costs for such month.

Within 120 days after the end of each Transmission Service Year, the Authority will submit to each Project Participant a statement of the actual amounts payable under the Transmission Service Contracts for such year and any adjustments to such amounts for any prior year, based on the annual audit required by the Transmission Service Contracts. If for any Transmission Service Year the actual amounts payable under the Transmission Service Contracts exceed the amount which the Project Participants have been billed, the Project Participants shall promptly pay the amount of such excess to the Authority; if such amounts are less than the amounts billed, the Authority will credit the excess against the Project Participants’ next monthly payment.

In the event of a default or inability to perform by a Project Participant under its Transmission Service Contract, the Authority shall proceed to enforce the Project Participant’s covenants or obligations thereunder, or seek damages or injunctive relief for the breach thereof, by action at law or equity. The Transmission Service Contracts also provide that if a payment due under a Transmission Service Contract remains unpaid when due, the Authority may, upon 90 days’ written notice to the Project Participant,
discontinue transmission service to such Project Participant while the default continues. Except as a result of the receipt of payments due to a transfer of the defaulting Project Participant’s rights to transmission service, the discontinuance of transmission service to a defaulting Project Participant by the Authority will not reduce the obligation of such Project Participant to make payments under its Transmission Service Contract. See “SUMMARY OF CERTAIN PROVISIONS OF THE TRANSMISSION SERVICE CONTRACTS” in Appendix C hereto for a discussion of certain additional provisions of the Transmission Service Contracts.

Authority Rate Covenant

Pursuant to the 2015 Series C Subordinated Indenture, the Authority has covenanted to at all times establish charges and cause to be collected amounts for the use of Authority Capacity (including amounts payable under the Transmission Service Contracts) as shall be required to provide Revenues at least sufficient, together with other available funds, for the payment each Fiscal Year of all amounts required to be paid from Revenues or Available Revenues during such Fiscal Year pursuant to the Senior Indenture, together with all amounts required to be paid from Pledged Revenues pursuant to the 2015 Series C Subordinated Indenture, and all amounts required to be paid from Available Revenues pursuant to the Prior Subordinated Indentures.

Budgeting

The Transmission Service Contracts and the 2015 Series C Subordinated Indenture require the Authority to adopt an Annual Budget not less than 30 days prior to the beginning of each Transmission Service Year. Each Annual Budget will set forth a detailed estimate of the Monthly Transmission Costs and all Revenues, income or other funds to be applied to such costs, for and applicable to such Transmission Service Year. See “SECURITY AND SOURCES OF PAYMENT FOR THE SENIOR BONDS AND THE SUBORDINATE BONDS – Transmission Service Contracts.” Each Subordinated Indenture, including the 2015 Series C Subordinated Indenture, requires the Authority, following the end of each quarter of each Fiscal Year, to review its estimates set forth in the Annual Budget for such Fiscal Year and, in the event such estimates do not substantially correspond with actual revenues, expenses or other requirements, adopt an amended Annual Budget. The Authority will also adopt an amended Annual Budget, in accordance with the Transmission Service Contracts, if (i) there are at any time during the Fiscal Year extraordinary receipts or payment of unusual costs relating to Authority Capacity or (ii) the amounts in the Payment Account, the Reserve Account, if any, or the Charges Account in the Issue Fund under each Subordinated Indenture are less than the respective balances required therein by such Subordinated Indenture. The Authority may also at any time, in accordance with the provisions of the Transmission Service Contracts, adopt an amended Annual Budget for the remainder of the then current Fiscal Year.

Flow of Funds

The Senior Indenture establishes the following Funds and Accounts (each of which is held by the Senior Indenture Trustee): Construction Fund, Revenue Fund, Operating Fund, Debt Service Fund (including the Debt Service Account and the Debt Service Reserve Account), Bond Anticipation Note Fund, Reserve and Contingency Fund (including the Renewal and Replacement Account and the Reserve Account) and General Reserve Fund, and several refunding escrow funds.

The 2015 Series C Subordinated Indenture establishes the 2015 Series C Issue Fund (which is held by the Trustee) and establishes within the 2015 Series C Issue Fund the following Accounts: the 2015 Series C Pledged Revenues Account, the 2015 Series C Payment Account, the 2015 Series C Reserve Account, the 2015 Series C Charges Account, the 2015 Series C Remainder Account and the 2015 Series C Costs of Issuance Account.
“Revenues” under the Senior Indenture are (i) all revenues, income, rents and receipts derived or to be derived by the Authority from or attributable to Authority Capacity or to the payment of the costs thereof received or to be received by the Senior Indenture Trustee under the Transmission Service Contracts or under any other contract for the sale by the Authority of Authority Capacity or any part thereof or any contractual arrangement with respect to the use of Authority Capacity 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 Authority Capacity, (iii) interest received or to be received on any moneys or securities (other than in the Construction Fund) held pursuant to the Senior Indenture and required to be paid into the Revenue Fund, (iv) interest received on any moneys or securities held pursuant to the Prior Subordinated Indentures and the 2015 Series C Subordinated Indenture and required by their terms to be paid into the Revenue Fund, (v) amounts received by or on behalf of the Authority pursuant to any Parity Swap, (vi) amounts received by or on behalf of the Authority pursuant to any subordinate swap agreement or similar agreement that provides therein (including in any schedule or attachment thereto) that payments received by or on behalf of the Authority pursuant thereto shall constitute Revenues under the Senior Indenture, and (vii) amounts received by or on behalf of the Authority pursuant to any Cap Agreement (as defined in the Senior Indenture).

Pursuant to the Senior Indenture, all Revenues received are to be deposited promptly in the Revenue Fund. Amounts in the Revenue Fund are to be paid monthly to the following Funds and Accounts in the following order of priority:

(1) To the Operating Fund, a sum which, together with any amount in the Operating Fund not set aside as reserves, equals the total moneys appropriated for Authority Operating Expenses (which include Monthly Power Costs allocable to the Southern Transmission Project) in the Annual Budget for the then current month.

(2) To the Debt Service Fund (i) for credit to the Debt Service Account, the amount, if any, required so that the balance in said Account shall equal the Accrued Aggregate Debt Service on the outstanding Senior Bonds, if any, as of the last day of the then current month; and (ii) for credit to the Debt Service Reserve Account for the outstanding Senior Bonds, if any, the amount, if any, required for such Account to equal the Debt Service Reserve Requirement for the outstanding Senior Bonds, if any, as of the last day of the then current month. There are currently no outstanding Senior Bonds.

(3) To the Bond Anticipation Note Fund, the amount, if any, required so that the balance in said Fund, together with the amount on deposit in any fund established pursuant to the proceedings authorizing Notes and lawfully available to pay interest on outstanding Notes accrued and unpaid and to accrue to the end of the then current calendar month, shall equal all interest accrued and unpaid and to accrue on outstanding Notes to the end of the then current calendar month. The Senior Indenture Trustee will apply amounts in the Bond Anticipation 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. There are currently no outstanding Notes.

(4) To the Reserve and Contingency Fund, for credit to the Renewal and Replacement Account and the Reserve Account, the respective amounts provided for such purposes for the then current month in the current Annual Budget.

(5) To the General Reserve Fund, the balance, if any, in the Revenue Fund. The Authority must transfer from the General Reserve Fund amounts in the following order of priority: (a) to the Debt Service Account and the Debt Service Reserve Account in the Debt
Service Fund for the Senior Bonds the amount necessary (or all the moneys in the General Reserve Fund if less than the amount necessary) to make up any deficiencies in required payments to said Accounts; (b) in the event of any transfer of moneys from said Debt Service Reserve Account to said Debt Service Account for the Senior Bonds, to said Debt Service Reserve Account the amount of the deficiency in such Account resulting from such transfer; and (c) to the Renewal and Replacement Account and the Reserve Account in the Reserve and Contingency Fund the amount necessary (or all the moneys in the General Reserve Fund if less than the amount necessary) to make up any deficiencies in required payments to said Accounts.

Thereafter, on or before the last business day of each calendar month, Available Revenues, (i) to the extent required to provide for the Indenture Requirements under each Prior Subordinated Indenture for such month and (ii) to the extent required to be deposited into the 2015 Series C Payment Account, the 2015 Series C Reserve Account (if applicable) and the 2015 Series C Charges Account in the 2015 Series C Issue Fund for such month, are to be transferred ratably from amounts remaining in the General Reserve Fund by the Senior Indenture Trustee to the trustee for each Prior Subordinated Indenture and to the Trustee for deposit in the 2015 Series C Pledged Revenues Account. Moneys set aside to meet the requirements of the 2015 Series C Subordinated Indenture and each Prior Subordinated Indenture (or any future subordinate indenture) shall be applied in a manner such that none shall have priority over or otherwise rank prior to the others. Available Revenues upon their deposit in the 2015 Series C Pledged Revenues Account become Pledged Revenues, free and clear of the lien and pledge of the Senior Indenture.

Pursuant to the 2015 Series C Subordinated Indenture, as soon as practicable in each month after the deposit of Pledged Revenues into the 2015 Series C Pledged Revenues Account, but in any case no later than 12:00 noon, New York City time, on the last Business Day of such month, the Pledged Revenues are to be transferred from the 2015 Series C Pledged Revenues Account to the following Accounts in the following order of priority:

(1) To the 2015 Series C Payment Account, the amount, if any, required so that the balance in said Account shall equal the sum of (A) the 2015 Series C Accrued Debt Service as of the last day of the current month, and (B) all amounts due and payable by the Authority under any Parity Swaps (if any) during such month (or the entire amount so transferred by the Trustee from the 2015 Series C Pledged Revenues Account if less than the required amount).

(2) To the 2015 Series C Reserve Account, upon the occurrence of any deficiency therein (if applicable) (a) if the 2015 Series C Reserve Account is at that time funded by a Reserve Account Policy the provider of which has not failed to make payments thereunder, the amount of each unreplenished prior withdrawal from the 2015 Series C Reserve Account so that the provider of the Reserve Account Policy has been repaid for any draw made under such Policy for such Account or (b) if the 2015 Series C Reserve Account is not at that time funded by a Reserve Account Policy or, if funded by a Reserve Account Policy, the provider of such Reserve Account Policy has failed to make payment thereunder, the amount, if any, required for such Account to equal the Reserve Requirement as of the last day of the then current month (or the entire amount so transferred by the Trustee from the 2015 Series C Pledged Revenues Account after making the deposit in clause (1) above if less than the required amount). Pursuant to the 2015 Series C Subordinated Indenture, the Reserve Requirement for the 2015 Series C Subordinate Bonds shall be equal to $0.00, and the 2015 Series C Reserve Account will not be funded.

(3) To the 2015 Series C Charges Account, the amount, if any, required so that the balance in such Account equals the sum of all amounts accrued or due and payable by the
Authority as fees and charges to the Trustee or the Paying Agent during such month (or the entire amount so transferred by the Trustee from the 2015 Series C Pledged Revenues Account after making the deposits in clauses (1) and (2) above if less than the required amount).

(4) To the 2015 Series C Remainder Account, the remaining balance, if any, of moneys in the 2015 Series C Pledged Revenues Account after making the above deposits.

No Funded 2015 Series C Reserve Account

Pursuant to the 2015 Series C Subordinated Indenture, the Reserve Requirement for the 2015 Series C Subordinate Bonds shall be equal to $0.00, and the 2015 Series C Reserve Account will not be funded.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

Formation

The Authority, a joint powers agency and a public entity organized under the laws of the State of California, was created pursuant to the Act and the Joint Powers Agreement for the purpose of the planning, financing, development, acquisition, construction, operation and maintenance of projects for the generation or transmission of electric energy. The Joint Powers Agreement has a term expiring in 2030 or such later date as all bonds and notes of the Authority and interest thereon have been paid in full or adequate provision for such payment has been made in accordance with the instruments governing such bonds and notes.

Organization and Management

The Authority is governed by a Board of Directors which consists of one representative for each of the members. The current representatives are listed on the masthead page of this Official Statement. The management of the Authority is under the direction of its Executive Director, Bill D. Carnahan, who serves at the pleasure of the Board of Directors. Mr. Carnahan also serves as the Treasurer/Auditor of the Authority. Prior to his appointment as Executive Director in 2000, Mr. Carnahan served as the Public Utilities Director of the Public Utilities Department for the City of Riverside beginning in 1986. During a portion of his 46-year career, Mr. Carnahan also served as the manager at various municipal utilities in Colorado. Mr. Carnahan served on the Authority’s Board of Directors from 1986 until 2000 and was the Authority’s President during 1995 and 1996. Mr. Carnahan also served on the American Public Power Association’s Board of Directors from 1979 to 1988 and was its President during 1987. He has also served on the California Municipal Utilities Association’s Board of Governors since 1988 and was its President during 1993 and 1994. Mr. Carnahan also served on the California Independent System Operator’s Board of Directors between 1996 and early 2001.

The other officers of the Authority are selected by the Board of Directors. The President of the Authority is Fred H. Mason, Electric Utility Director of the City of Banning. Mr. Mason has served as Electric Utility Director of the City of Banning since 2009. Prior to that time he was the City of Banning’s Power Resource & Revenue Administrator since 2001. The Vice President of the Authority is Girish Balachandran, Public Utilities General Manager for the City of Riverside. Mr. Balachandran was appointed the Public Utilities General Manager for the City of Riverside in January 2014. He has nearly 23 years of experience in municipal government, including previously serving as General Manager of Alameda Municipal Power, the electric utility of the City of Alameda, since 2007.

The position of Director of Finance & Accounting of the Authority is currently under recruitment. In the interim, prior to the appointment of a new Director of Finance & Accounting for the Authority,
such services are being provided under a consulting agreement with Michael Bell Management Consulting.

With respect to any matter involving the acquisition and financing or refinancing of an Authority project to be decided by the Board of Directors, each Director is entitled to cast votes weighted according to the size of the entitlement to the project of each project participant in addition to the vote each Director is entitled to cast as a member of the Authority. All such matters must be decided by at least 80% of the votes cast, and no such vote may be taken unless there shall be present at the meeting Directors entitled to cast more than 50% of the votes relative to such matter. Voting by the Board of Directors may take place at meetings of the Board of Directors when a quorum is present. A majority of the Board of Directors constitutes a quorum.

The Authority has entered into the Agency Agreement pursuant to which the Department, as agent, represents, and undertakes certain activities on behalf of, the Authority in connection with the Authority’s payments-in-aid of construction and the acquisition and financing or refinancing of Authority Capacity. The Agency Agreement gives the agent the responsibility of (a) undertaking those activities necessary (i) to secure regulatory approvals to allow the Authority to acquire Authority Capacity, (ii) to determine the cost of acquisition of Authority Capacity Interest, (iii) to formulate arrangements for the transmission of Authority Capacity to the Project Participants, (iv) to formulate the financing program and develop financing documents and (v) to acquire Authority Capacity, and (b) representing the Authority with respect to matters arising under or in connection with the Project Agreements (as defined in the Agency Agreement) or the acquisition of Authority Capacity.

Other Activities of the Authority

In addition to the Southern Transmission Project, the following are the projects of the Authority that have been financed by bonds issued by the Authority. The principal of, premium, if any, and interest on the 2015 Series C Subordinate Bonds are secured solely by and payable solely from Pledged Revenues as described herein. None of the costs associated with the projects described below in this subsection is payable from such Pledged Revenues.

**Palo Verde Nuclear Generating Station.** The Authority, pursuant to the Arizona Nuclear Power Project Participation Agreement, has a 5.91% ownership interest in Palo Verde Nuclear Generating Station Units 1, 2 and 3 (the “Generating Station”), including certain associated facilities and contractual rights, a 5.44% ownership interest in the Arizona Nuclear Power Project High Voltage Switchyard (the “Switchyard”) and contractual rights, and a 6.55% share of the rights to use certain portions of Arizona Nuclear Power Project Valley Transmission System. The Generating Station and the Switchyard are collectively referred to herein as “PVNGS.”

The Authority has sold the entire capability of the Authority’s interest pursuant to power sales contracts with nine California cities and a California irrigation district, each of which is a member of the Authority. The California cities of Azusa, Banning, Burbank, Colton, Glendale, Pasadena, Riverside and Vernon as well as the Department and the Imperial Irrigation District (“IID”) are PVNGS project participants. Under the PVNGS power sales contracts, the participants are entitled to the Authority generation capability based on their respective PVNGS entitlements and are obligated to make payments on a “take-or-pay” basis.

Commercial operation and initial deliveries from PVNGS Units 1, 2 and 3 commenced in 1986 and 1987. In addition to the transmission lines for the Mead-Adelanto Project and the Mead-Phoenix Project, transmission is accomplished through agreements with Salt River Project, the Department and Southern California Edison Company. The Authority had outstanding $36,130,000 aggregate principal amount of revenue bonds with respect to PVNGS as of January 1, 2015.
Mead-Phoenix Transmission Project. The Mead-Phoenix Transmission Project consists of a 256-mile, 500-kV alternating current (“AC”) transmission line that extends between a southern terminus at the existing Westwing Substation (in the vicinity of Phoenix, Arizona) and a northern terminus at Marketplace Substation, a substation located approximately 17 miles southwest of Boulder City, Nevada. The line is looped through the 500-kV switchyard constructed in the existing Mead Substation in southern Nevada with a transfer capability of 1,923 MW (as a result of upgrades completed in 2009). By connecting to Marketplace Substation, the Mead-Phoenix Transmission Project interconnects with the Mead-Adelanto Transmission Project and with the existing McCullough Substation. The Mead-Phoenix Transmission Project is comprised of three project components. The Authority has executed an ownership agreement providing it with an 18.3077% member-related ownership share in the Westwing-Mead project component, a 17.7563% member-related ownership share in the Mead Substation project component, and a 22.4082% member-related ownership share in the Mead-Marketplace project component. Other owners of the line are Arizona Public Service Company, M-S-R Public Power Agency, Salt River Project and the City of Vernon, California (whose interest was subsequently transferred to Startrans IO, L.L.C.). The Authority has sold, on a “take-or-pay” basis, the entire capability of its member-related ownership interest through transmission service contracts with nine members of the Authority (all of the Authority members with the exception of IID and the California cities of Cerritos and Vernon). The Authority has two separate and independent ownership interests in this project: one interest for the Authority’s members participating in the project, and one interest for Western Area Power Administration (“Western”) which provides the funding for that interest. The commercial operation date for the project was April 15, 1996. The Authority had outstanding $33,175,000 aggregate principal amount of revenue bonds with respect to the Mead-Phoenix Transmission Project as of January 1, 2015. See “– Multiple Project Revenue Bonds” below.

Mead-Adelanto Transmission Project. The Mead-Adelanto Transmission Project consists of a 202-mile, 500-kV AC transmission line that extends between a southwest terminus at the existing Adelanto Substation in southern California and a northeast terminus at Marketplace Substation, a substation located approximately 17 miles southwest of Boulder City, Nevada. By connecting to Marketplace Substation, the line interconnects with the Mead-Phoenix Transmission Project and the Mead-Adelanto Transmission Project interconnects with the existing McCullough Substation in southern Nevada. The line has a transfer capability of 1,291 MW. The Authority has executed an ownership agreement providing it with a total of a 67.9167% member-related ownership share in the project. The other owners of the line are M-S-R Public Power Agency and the City of Vernon, California (whose interest was subsequently transferred to Startrans IO, L.L.C.). The Authority has sold the entire capability of its member-related ownership interest, on a “take-or-pay” basis, through transmission service contracts with nine members of the Authority (all of the Authority members with the exception of IID and the California cities of Cerritos and Vernon). The Authority has two separate and independent ownership interests in this project: one interest for the Authority’s members participating in the project, and one interest for Western which provides the funding for that interest. The commercial operation date for the project was April 15, 1996, which coincided with the completion of the Mead-Phoenix Transmission Project. The Authority had outstanding $108,785,000 aggregate principal amount of revenue bonds with respect to the Mead-Adelanto Transmission Project as of January 1, 2015. See “– Multiple Project Revenue Bonds” below.

Multiple Project Revenue Bonds. In January 1990, the Authority issued $647,750,000 of its Multiple Project Revenue Bonds for the purpose of funding electric generation and/or transmission projects undertaken by the Authority. Proceeds of the financing available for the funding of such projects initially amounted to approximately $600,000,000. Upon the request of the Authority’s members, the approval of its Board of Directors, and the meeting of other preconditions, portions of such proceeds could be transferred to fund capital costs of a selected Authority project. In October 1992, the Authority transferred $103,600,000 of such proceeds to fund costs of the Authority’s interest in the Mead-Phoenix...
Transmission Project. In October 1992, the Authority also transferred $285,000,000 of such proceeds to fund costs of the Authority’s interest in the Mead-Adelanto Transmission Project. Since July 1, 2013, no Multiple Project Revenue Bonds have been outstanding, but the related indenture of trust remains in effect in connection with the revenue bonds for the Mead-Phoenix Transmission Project and the Mead-Adelanto Transmission Project described above.

Hoover Uprating Project. The Hoover Uprating Project consists principally of the uprating of the capacity of 17 generating units at the hydroelectric power plant of the Hoover Dam, located approximately 25 miles from Las Vegas, Nevada. Modern insulation technology made it possible to “uprate” the nameplate capacity of existing generators (the “Hoover Uprating Project”). The California cities of Anaheim, Azusa, Banning, Burbank, Colton, Glendale, Pasadena, Riverside and Vernon have obtained entitlements totaling 127 MW of capacity and approximately 143,000 megawatt-hours (“MWh”) of allocated energy annually from the Hoover Uprating Project. In 1987, to reflect these entitlements, these cities entered into contracts with the United States Bureau of Reclamation (the “Bureau”) providing for the advancement of funds for the uprating and with Western for the purchase of power from the Hoover Uprating Project. Subsequently, the California cities of Anaheim, Riverside, Burbank, Azusa, Colton and Banning (the “Hoover Participants”) entered into assignment agreements with the Authority to assign their entitlements in return for the Authority’s agreement to provide funds to the Bureau to pay for the Hoover Participants’ share of the Hoover Uprating Project costs. Based on Western’s allocations and the assignment agreements, the Authority’s share of the Hoover Uprating Project is approximately 94 MW of capacity and approximately 107,000 MWh of associated energy annually. The Hoover Participants and the Authority have executed power sales contracts under which the Hoover Participants have agreed to make monthly payments on a “take-or-pay” basis in exchange for their shares of the Authority’s share of Hoover capacity and allocated energy. As of January 1, 2015, the Authority had outstanding $6,095,000 aggregate principal amount of revenue bonds with respect to the Hoover Uprating Project.

San Juan Unit 3 Project. The San Juan Generating Station (“San Juan”) consists of a 4-unit, coal-fired electric generating station located in northwestern New Mexico, approximately 15 miles northwest of the City of Farmington, in San Juan County. The combined net generating capacity of the four units is 1,647 MW, with the net generating capacity of Unit 3 being 497 MW. The four units were put into operation between 1976 and 1982. In 1993, the Authority and five of its members negotiated a purchase agreement with Century Power Corporation, under which the Authority purchased a 41.8% interest in Unit 3 and related common facilities of San Juan, entitling the Authority to approximately 208 MW of power generated by Unit 3. In this regard, the Authority entered into power sales contracts with the California cities of Azusa, Banning, Colton and Glendale, and IID. Under these power sales contracts, the Authority sells 100% of its entitlement to capacity and energy of Unit 3 on a “take-or-pay” basis. As of January 1, 2015, the Authority had outstanding $42,935,000 aggregate principal amount of a revenue bond with respect to San Juan.

In June 2014, the nine owners of San Juan reached a non-binding agreement in principle on an ownership restructuring of San Juan that, if implemented, would result in the shutdown of Unit 3 by December 31, 2017 as part of the overall settlement of matters regarding emissions at San Juan. Most, but not all, of the regulatory approvals and other conditions have been obtained or satisfied in order to implement this proposed ownership restructuring.

Magnolia Power Project. The Magnolia Power Project (the “Magnolia Project”) consists of a natural gas-fired electric generating plant with a nominally rated net capacity of 242 MW and auxiliary facilities located in Burbank, California. The Magnolia Project is owned by the Authority and was constructed and acquired for the primary purpose of providing participants in the Magnolia Project with firm capacity and energy to help meet their power and energy requirements. The Magnolia Project is operated by Burbank. The Authority has entered into power sales agreements with the California cities of
Anaheim, Burbank, Cerritos, Colton, Glendale and Pasadena pursuant to which the Authority has sold 100% of its entitlement to capacity and energy in the Magnolia Project to such participants on a “take-or-pay” basis. The commercial operation date for the Magnolia Project was September 22, 2005. The Authority had outstanding $326,530,000 aggregate principal amount of revenue bonds with respect to the Magnolia Project as of January 1, 2015 (of which $11,900,000 relates exclusively to the City of Cerritos).

**Prepaid Natural Gas Project.** The Prepaid Natural Gas Project primarily consists of the acquisition by the Authority of the right to receive an aggregate amount of approximately 135 billion cubic feet of natural gas (which amount has been reduced to approximately 90 billion cubic feet as a result of the restructuring described below) from J. Aron & Company (“J. Aron”) pursuant to the terms of five Prepaid Natural Gas Sales Agreements between the Authority and J. Aron, each relating to a separate participant. The gas is delivered by J. Aron to the Authority at designated delivery points on the natural gas pipelines that serve the participants in specified daily quantities each month, over the approximately 30-year term (now 27-year term due to the restructuring) of each of the Prepaid Natural Gas Sales Agreements, in exchange for the lump sum prepayment made to J. Aron by the Authority on the date of issuance of the Authority’s Gas Project Revenue Bonds (Project No. 1) in 2007. Prepaid Natural Gas Project participants are the California cities of Anaheim, Burbank, Colton, Glendale and Pasadena. On October 22, 2009, the Prepaid Natural Gas Sales Agreements between the Authority and J. Aron were restructured to provide an acceleration of a portion of the long-term savings, reduce the remaining volumes of gas to be delivered and shorten the overall duration of the agreements. As a result of the restructuring, approximately $165,000,000 principal amount of bonds with respect to the Prepaid Natural Gas Project was discharged. On September 19, 2013, the transaction was further restructured to, among other things (a) provide additional credit support for payments by three of the project participants by amending and restating the associated receivables purchase agreement and The Goldman Sachs Group, Inc. guaranty, (b) replace AIG-FP Broadgate Limited with Mitsubishi UFJ Securities International plc as the counterparty to the Authority commodity swaps, and (c) create a custodial arrangement with respect to payments owed by J. Aron and guaranteed by The Goldman Sachs Group, Inc. or to J. Aron under corresponding J. Aron commodity swaps in order to mitigate the Authority’s credit exposure to Mitsubishi UFJ Securities International plc as the counterparty. The Authority has sold 100% of its interest in the natural gas, on a “take-and-pay” basis, through gas supply agreements with the California cities of Anaheim, Burbank, Colton, Glendale and Pasadena. The Authority had outstanding $309,615,000 aggregate principal amount of revenue bonds with respect to the Prepaid Natural Gas Project as of January 1, 2015.

**Natural Gas Project.** The Natural Gas Project includes the Authority’s leasehold interests in (i) certain natural gas resources, reserves, fields, wells and related facilities located near Pinedale, Wyoming (the “Wyoming Subproject”) and (ii) certain natural gas resources, reserves, fields, wells and related facilities in (or near) the Barnett Shale geological formation in Texas (the “Texas Subproject,” and collectively with the Wyoming Subproject, the “Natural Gas Project”). The Authority has sold the entire production capacity of its leasehold interests in the Natural Gas Project by entering into gas sales agreements with the California cities of Anaheim, Burbank and Colton (collectively, the “Natural Gas Project A Participants”) and with the California cities of Glendale and Pasadena on a “take-or-pay” basis (other than with respect to debt service, which is payable only by the Natural Gas Project A Participants on a several basis). On February 6, 2008, the Authority issued revenue bonds in three simultaneous financings (each for the benefit of a Natural Gas Project A Participant). As of January 1, 2015, the Authority had outstanding $82,925,000 aggregate principal amount of Natural Gas Project A Revenue Bonds, consisting of $47,865,000, $25,160,000 and $9,900,000 aggregate principal amount of the Anaheim series, the Burbank series and the Colton series, respectively.

**Canyon Power Project.** The Canyon Power Project consists of a simple cycle, natural gas-fired power generating plant, comprised of four General Electric LM 6000PC Sprint combustion turbines with
a combined nominally rated net base capacity of 200 MW, and auxiliary facilities located on approximately 10 acres of land within an industrial area of the City of Anaheim, California. The Canyon Power Project is owned by the Authority and operated and maintained by the City of Anaheim. The Canyon Power Project was constructed for the primary purpose of providing the City of Anaheim with firm capacity and energy to help it meet its current and future capacity and energy requirements and to satisfy certain ancillary services requirements. The Canyon Power Project achieved full commercial operation in 2011. The Authority has entered into a power sales agreement with the City of Anaheim pursuant to which the Authority has sold 100% of its entitlement to capacity and energy in the Canyon Power Project to the City of Anaheim on a “take-or-pay” basis. As of January 1, 2015, the Authority had outstanding $301,470,000 aggregate principal amount of revenue bonds with respect to the Canyon Power Project.

Linden Wind Energy Project. The Linden Wind Energy Project consists of the acquisition by the Authority of an approximately 50 MW nameplate capacity, wind powered electric generating facility comprised of 25 wind turbines located near the town of Goldendale in Klickitat County, Washington, including the structures, facilities, equipment, fixtures, improvements and associated real and personal property and other rights and interests necessary for the ownership and operation of the generation facility and the sale of energy therefrom. The Linden Wind Energy Project was developed and constructed by Northwest Wind Partners, LLC (“Northwest Wind”), a Delaware limited liability company. Northwest Wind undertook the development, construction, start-up, testing and commissioning of the project, and upon the completion thereof and subject to the terms of the Asset Purchase Agreement, dated as of June 23, 2009, by and between the Authority and Northwest Wind, the Authority acquired the project from Northwest Wind. The Authority has entered into power sales agreements with the Department and the California city of Glendale pursuant to which the Authority has sold 100% of its entitlement to capacity and energy in the Linden Wind Energy Project to such participants on a “take-or-pay” basis. As of January 1, 2015, the Authority had outstanding $125,500,000 aggregate principal amount of revenue bonds with respect to the Linden Wind Energy Project.

Tieton Hydropower Project. The Tieton Hydropower Project consists of a 13.6 MW nameplate capacity “run of the reservoir” hydroelectric generation facility, comprised of (i) a powerhouse located near Rimrock Lake in Yakima County approximately 40 miles west of the City of Yakima, Washington, and constructed at the base of the Bureau’s Tieton Dam on the Tieton River, (ii) a 21-mile 115 kV transmission line from the power plant substation to the point of interconnection with the electrical grid, and (iii) related assets, property and contractual rights, acquired by the Authority in November 2009, pursuant to an Asset Purchase Agreement, dated as of October 19, 2009, by and between the Authority and Tieton Hydropower, L.L.C., a Washington limited liability company. The Authority has entered into power sales and acquisition contracts with the California cities of Burbank and Glendale pursuant to which the Authority has sold 100% of its entitlement to capacity and energy in the Tieton Hydropower Project to such participants on a “take-or-pay” basis. As of January 1, 2015, the Authority had outstanding $49,670,000 principal amount of revenue bonds with respect to the Tieton Hydropower Project.

Milford Wind Corridor Phase I Project. The Milford Wind Corridor Phase I Project consists of the purchase by the Authority of all energy generated by a 203.5 MW nameplate capacity, wind powered electric generating facility located near Milford, Utah (the “Milford I Facility”), for a term of 20 years (unless earlier terminated), pursuant to a Power Purchase Agreement, dated as of March 16, 2007, as amended, by and between the Authority and Milford Wind Corridor Phase I, LLC, a Delaware limited liability company, as the owner of the Milford I Facility. The generating facility includes 97 wind turbines, consisting of 58 Clipper C99 wind turbine generators, each with a rated capacity of 2.5 MW, and 39 General Electric 1.5xle wind turbine generators, each with a rated capacity of 1.5 MW. Pursuant to the Power Purchase Agreement, energy from the Milford I Facility is delivered to the Authority over an
approximately 88-mile, 345 kV, transmission line extending from the wind generation site to the IPP Switchyard in Delta, Utah, an ownership interest in which transmission line, together with certain structures, facilities, equipment, fixtures, improvements and associated real and personal property interests and other rights and interests necessary for the ownership and operation of the generation facility and the sale of energy therefrom, comprise a part of the Milford I Facility. From the IPP Switchyard, the energy is delivered to the Adelanto Converter Station in California. On February 9, 2010, the Authority issued $237,235,000 aggregate principal amount of revenue bonds in order to finance the purchase by prepayment of a specified quantity of energy from the Milford I Facility over the 20-year delivery term (with a guaranteed annual quantity in each year), commencing on the commercial operation date of the Milford I Facility (i.e., November 16, 2009). The Authority has entered into power sales agreements with the Department and the California cities of Burbank and Pasadena pursuant to which the Authority has sold 100% of its entitlement to capacity and energy in the Milford Wind Corridor Phase I Project to such participants on a “take-or-pay” basis. As of January 1, 2015, the Authority had outstanding $205,195,000 aggregate principal amount of revenue bonds with respect to the Milford Wind Corridor Phase I Project. This project is to be distinguished from the Milford Wind Corridor Phase II Project, which is described below.

**Milford Wind Corridor Phase II Project.** The Milford Wind Corridor Phase II Project consists of the purchase by the Authority of all energy generated by a 102 MW nameplate capacity, wind powered electric generating facility comprised of 68 wind turbines located near Milford, Utah (the “Milford II Facility”), for a term of 20 years (unless earlier terminated) pursuant to a Power Purchase Agreement, dated as of March 1, 2010, by and between the Authority and Milford Wind Corridor Phase II, LLC, a Delaware limited liability company, as the owner of the Milford II Facility. Pursuant to the Power Purchase Agreement, energy from the Milford II Facility is delivered to the Authority over an approximately 90-mile, 345 kV, transmission line extending from the wind generation site to the IPP Switchyard in Delta, Utah, an ownership interest in which transmission line, together with certain structures, facilities, equipment, fixtures, improvements and associated real and personal property interests and other rights and interests necessary for the ownership and operation of the generation facility and the sale of power therefrom, comprise a part of the Milford II Facility. From the IPP Switchyard, the energy is delivered to the Adelanto Converter Station in California. On August 25, 2011, the Authority issued $157,465,000 aggregate principal amount of revenue bonds in order to finance the purchase by prepayment of a specified quantity of energy from the Milford II Facility over the 20-year delivery term (with a guaranteed annual quantity in each year), commencing on the commercial operation date of the Milford II Facility (i.e., May 2, 2011). The Authority has entered into power sales agreements with the Department and the California city of Glendale pursuant to which the Authority has sold 100% of its entitlement to capacity and energy in the Milford Wind Corridor Phase II Project to such participants on a “take-or-pay” basis. As of January 1, 2015, the Authority had outstanding $142,895,000 aggregate principal amount of revenue bonds with respect to the Milford Wind Corridor Phase II Project. This project is to be distinguished from the Milford Wind Corridor Phase I Project, which is described above.

**Windy Point/Windy Flats Project.** The Windy Point/Windy Flats Project consists primarily of the purchase by the Authority of all energy generated by a 262.2 MW nameplate capacity, wind powered electric generating facility comprised of 114 wind turbines and related facilities located in the Columbia Hills area of Klickitat County, Washington near the City of Goldendale (the “Windy Point/Windy Flats Facility”), for a term of 20 years (unless earlier terminated), pursuant to the terms of a Power Purchase Agreement (the “Windy Point/Windy Flats Power Purchase Agreement”), dated as of June 24, 2009, by and between the Authority and the Windy Flats Partners, LLC, a Delaware limited liability company, the owner of the Windy Point/Windy Flats Facility. Pursuant to the Windy Point/Windy Flats Power Purchase Agreement, energy from the Windy Point/Windy Flats Facility is delivered to Klickitat Public Utility District (“KPUD”) Dooley and Energizer Substations over the KPUD 230-kV transmission line to the point of delivery at the Bonneville Power Administration Rock Creek Substation. On September 9,
2010, the Authority issued $514,160,000 aggregate principal amount of revenue bonds in order to finance
the purchase by prepayment of a specified quantity of energy from the Windy Point/Windy Flats Facility
over the 20-year delivery term (with a guaranteed annual quantity in each year), commencing on the
commercial operation date of the first phase of the Windy Point/Windy Flats Facility (i.e., January 25,
2010). The Authority has entered into power sales agreements with the Department and the California
city of Glendale pursuant to which the Authority has sold 100% of its entitlement to the capacity and
energy in the Windy Point/Windy Flats Project to such participants on a take-or-pay basis. As of
January 1, 2015, the Authority had outstanding $446,775,000 aggregate principal amount of revenue
bonds with respect to the Windy Point/Windy Flats Project.

**Apex Power Project.** The Apex Power Project consists of a natural gas-fired, combined cycle
generating facility, nominally rated at 531 MW, located in Clark County, Nevada, generator
interconnection facilities, related assets and property, and interconnection and transmission contractual
rights. The facility commenced full commercial operation in May of 2003. The Apex Power Project was
acquired by the Authority in March 2014, pursuant to an Asset Purchase Agreement, dated as of
October 17, 2013, by and between the Authority and Las Vegas Power Company, LLC, a Delaware
limited liability company, the previous owner of the Apex Power Project. Operation and maintenance of
the Apex Power Project facility is currently provided pursuant to an Operations and Maintenance
Agreement with Wood Group Power Operations (West), Inc. and a Long-Term Service Agreement with
General Electric International, Inc., each of which was assumed by the Authority in connection with the
acquisition of the project. Firm transmission service for the facility output is provided pursuant to a Large
Generator Interconnection Agreement with Nevada Power Company and two Service Agreements for
Long-Term Firm Point-to-Point Transmission Service with a point of delivery at the Mead 230 kV
Substation. The Apex Power Project was acquired by the Authority for the primary purpose of providing
the Department with energy and base-load, combined cycle, gas-fired generating capacity. The Authority
has entered into a power sales agreement with the Department pursuant to which the Authority has sold
100% of its entitlement to capacity and energy in the Apex Power Project to the Department on a “take-
or-pay” basis. As of January 1, 2015, the Authority had outstanding $318,860,000 aggregate principal
amount of revenue bonds with respect to the Apex Power Project.

**Other projects of the Authority not Financed by Bonds**

The following are the projects of the Authority for which no bonds have been issued. The
principal of and premium, if any, and interest on the 2015 Series C Subordinate Bonds are secured solely
by and payable solely from Pledged Revenues as described herein. None of the costs associated with the
projects described below in this subsection is payable from such Pledged Revenues.

**Projects Currently Operating**

*Ameresco Landfill Gas Project.* The Authority, on behalf of the California cities of Burbank and
Pasadena, entered into a power purchase agreement for 10 MW of generating capacity. The agreement
expires on November 23, 2030.

*Don A. Campbell Geothermal Project.* The Authority, on behalf of the California city of Burbank
and the Department, entered into a power purchase agreement for 16 MW of generating capacity. The
agreement expires on January 1, 2034.

*Columbia Two Solar Project.* The Authority, on behalf of the California cities of Azusa,
Pasadena and Riverside, entered into a power purchase agreement for 15 MW of generating capacity.
The agreement expires on December 12, 2034.
Metropolitan Water District Small Hydropower Project. The Authority, on behalf of the California cities of Anaheim, Azusa and Colton, entered into a power purchase agreement for 17 MW of generating capacity. The agreement expires on December 23, 2023.

Ormat Geothermal Power Project. The Authority, on behalf of the California cities of Anaheim, Banning, Glendale and Pasadena, entered into a power purchase agreement for 16 MW of generating capacity. The agreement expires on January 1, 2034.

Pebble Springs Wind Power Project. The Authority, on behalf of the California cities of Burbank and Glendale and the Department, entered into a power purchase agreement for 99 MW of generating capacity. The agreement expires on February 11, 2027.

Projects Under Development

Antelope Big Sky Ranch Solar Project. The Authority, on behalf of the California cities of Azusa, Pasadena and Riverside, entered into a power purchase agreement for 20 MW of generating capacity. The effective date of the agreement will be determined after certain conditions are satisfied. When such conditions are satisfied, the agreement will expire 25 years thereafter.

Astoria 2 Solar Project. The Authority, on behalf of the California cities of Azusa, Banning, Colton and Vernon, entered into a power purchase agreement for 35 MW of generating capacity from commercial operation (currently expected to be November 15, 2016) to December 31, 2021 and 45 MW of generating capacity from January 1, 2022 until the expected expiration date of December 31, 2036.

Clearwater Solar Project. The Authority, on behalf of the California cities of Azusa, Pasadena and Riverside, entered into a power purchase agreement for 20 MW of generating capacity. The agreement expires on December 31, 2034. However, the Authority and the developer of this project are in dispute with respect to difficulties encountered by the developer in its unsuccessful efforts to obtain the necessary permits from the County of Kern, California. Currently it is not known what the outcome of this dispute will be.

Copper Mountain Solar 3 Project. The Authority, on behalf of the California city of Burbank and the Department, entered into a power purchase agreement for 250 MW of generating capacity. The commercial operation date is currently expected to be December 31, 2015, in which case the agreement will expire on December 31, 2036.

Heber 1 Geothermal Project. The Authority, on behalf of the Department and IID, entered into a power purchase agreement for 45 MW of generating capacity. The energy delivery commencement date is currently expected to be February 2, 2016. The power purchase agreement expires on February 2, 2026.

Kingbird Solar B Project. The Authority, on behalf of the California cities of Azusa, Colton and Riverside, entered into a power purchase agreement for 20 MW of generating capacity. The commercial operation date is currently expected to be December 31, 2015, in which case the agreement will expire on January 1, 2036.

Puente Hills Landfill Gas-to-Energy Project. The Authority, on behalf of the California cities of Azusa, Banning, Colton, Pasadena and Vernon, entered into a power purchase agreement for 43 MW of generating capacity. The commercial operation date is currently expected to be January 1, 2017, in which case the agreement will expire on December 31, 2030.
Springbok I Solar Farm Project. The Authority, on behalf of the Department, entered into a power purchase agreement for 100 MW of generating capacity. The commercial operation date is currently expected to be December 31, 2016, in which case the agreement will expire on January 1, 2041.

Summer Solar Project. The Authority, on behalf of the California cities of Azusa, Pasadena and Riverside, entered into a power purchase agreement for 20 MW of generating capacity. The effective date of the agreement will be determined after certain conditions are satisfied. When such conditions are satisfied, the agreement will expire 25 years thereafter.

Further Information

A copy of the Authority’s most recent Annual Report may be obtained from the Authority, 1160 Nicole Court, Glendora, California 91740. The Authority and each of the Project Participants maintains a website. However, the information presented therein is not part of this Official Statement and should not be relied upon in making investment decisions with respect to the 2015 Series C Subordinate Bonds.

THE SOUTHERN TRANSMISSION PROJECT

General Description

The Southern Transmission Project constitutes one of the components of IPP. See “INTERMOUNTAIN POWER AGENCY AND INTERMOUNTAIN POWER PROJECT – INTERMOUNTAIN POWER PROJECT” in Appendix B hereto for a more detailed description of IPP.

The Southern Transmission Project consists of: (a) the AC/DC Intermountain Converter Station adjacent to the IPP AC switchyard; (b) the ±500-kV DC bi-pole transmission line (“HVDC transmission line”), 488 miles in length, from the Intermountain Converter Station to the City of Adelanto, California; (c) the AC/DC Adelanto Converter Station, where the Southern Transmission Project connects to the switching and transmission facilities of the Department; and (d) related microwave communication system facilities. The HVDC transmission line is designed to have the capability of transmitting in excess of the aggregate Generation Station production anticipated to be delivered to the Project Participants. The AC/DC converter stations each consist of two solid state converter valve groups and have a combined rating of 2,400 MW (upgraded from 1,920 MW in 2010). The microwave communication system facilities are used for Generation Station dispatch, for IPP communication, and for control and protection of the Southern Transmission Project. The microwave system facilities are located along two routes between the Generation Station and Adelanto, forming a loop network.

By the execution of the Construction Management and Operating Agreement (as amended, the “Construction Management and Operating Agreement”), certain participants in IPP have designated the Department as Project Manager and Operating Agent for IPP, including the Southern Transmission Project. Actions and recommendations of the Department, in its role as Project Manager and Operating Agent, are subject to review, modification and approval by the IPP Coordinating Committee. The Department is required to construct, operate and maintain the Southern Transmission Project in accordance with prudent utility practices.

Operating Statistics

The Southern Transmission Project has operated with excellent availability and reliability. When one pole is out of service, the Southern Transmission Project is designed to operate in a mono-polar mode at a reduced capacity rating of 1,200 MW. Because the Southern Transmission Project is designed to operate in this manner, reliability for system planning purposes is essentially equivalent to that of two AC transmission lines. During the fiscal year ended June 30, 2014, transmission availability (one or both
poles on) was approximately 98.69%. The STS Upgrade Project increased the capacity of the Southern Transmission System from 1,920 MW to 2,400 MW. Scheduled outages are largely controlled to occur simultaneously with scheduled generating unit outages and thus do not interfere significantly with scheduled energy deliveries.

In the fiscal year ended June 30, 2014, the Project Participants received approximately 15 million MWh of energy over the line, consisting of a majority from IPP and the balance from Milford Wind Corridor Phase I Project, Milford Wind Corridor Phase II and various other purchases by certain of the Project Participants.

See “INTERMOUNTAIN POWER PROJECT AND INTERMOUNTAIN POWER AGENCY – INTERMOUNTAIN POWER PROJECT – General Description” in Appendix B for additional information regarding the operations of the Southern Transmission Project.

Arrangements for Transmission Service from Adelanto Converter Station

The Department has constructed a station and associated facilities to connect the Adelanto Converter Station with the Department’s main transmission system. The Department takes delivery of its share of the IPP Generating Station entitlements at the Adelanto Converter Station and provides transmission service for the other five Project Participants. The Department transmits the generation entitlements of the Cities of Glendale and Burbank directly to those cities’ respective systems. The Department transmits the generation entitlements of the City of Pasadena to an interconnection with Edison within the California Independent System Operator (“ISO”) control area. Transmission service from such delivery point to the City of Pasadena’s system is provided by the ISO. The City of Pasadena’s interconnection arrangement with Edison extends through 2040. The generation entitlements of the Cities of Anaheim and Riverside are delivered to their respective systems under the transmission service arrangement with the Department and transmission services purchased from the ISO.

Additionally, certain of the Project Participants will utilize their capacity rights in the IPP Switchyard, provided under agreements relating to the IPP, to accept energy delivered from the Authority’s Milford Wind Corridor Phase I Project and the Milford Wind Corridor Phase II Project, as well as from certain other projects not owned by the Authority, over the Southern Transmission System to the Adelanto terminal in California. The energy delivered at Adelanto is transmitted to the Project Participants’ respective electric systems under existing transmissions service arrangements.

The rights of the Project Participants under their existing IPP agreements for the delivery of the generation entitlements over the Southern Transmission System terminate on June 15, 2027.

Permits, Licenses and Approvals

The Southern Transmission Project, including the STS Upgrade Project, has been designed and constructed to operate in compliance with applicable federal, state and local regulations, codes, standards and laws. The Authority believes that all necessary permits, licenses and approvals have been secured.
The following Statement of Net Position has been prepared by the Authority based upon audited financial statements of the Authority for the fiscal years ended June 30, 2014 and June 30, 2013.

### Southern California Public Power Authority
### Southern Transmission System Project
### Statement of Net Position
### (In thousands)

<table>
<thead>
<tr>
<th></th>
<th>2014</th>
<th>2013 (as Restated)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>ASSETS</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Noncurrent assets</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Net utility plant</td>
<td>$261,767</td>
<td>$284,521</td>
</tr>
<tr>
<td>Investments - restricted</td>
<td>66,092</td>
<td>66,384</td>
</tr>
<tr>
<td>Advance to IPA – restricted</td>
<td>11,550</td>
<td>11,500</td>
</tr>
<tr>
<td>Total noncurrent assets</td>
<td>339,409</td>
<td>362,455</td>
</tr>
<tr>
<td>Current assets</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cash and cash equivalents – restricted</td>
<td>32,585</td>
<td>32,744</td>
</tr>
<tr>
<td>Cash and cash equivalents – unrestricted</td>
<td>146</td>
<td>3,643</td>
</tr>
<tr>
<td>Interest receivable</td>
<td>54</td>
<td>75</td>
</tr>
<tr>
<td>Accounts Receivable</td>
<td>3,834</td>
<td>--</td>
</tr>
<tr>
<td>Total current assets</td>
<td>36,619</td>
<td>36,462</td>
</tr>
<tr>
<td><strong>DEFERRED OUTFLOW OF RESOURCES</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Unamortized loss on refunding</td>
<td>50,438</td>
<td>69,188</td>
</tr>
<tr>
<td>Total deferred outflows of resources</td>
<td>50,438</td>
<td>69,188</td>
</tr>
<tr>
<td><strong>Total assets and deferred outflows of resources</strong></td>
<td>$426,466</td>
<td>$468,105</td>
</tr>
<tr>
<td><strong>LIABILITIES</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Noncurrent liabilities</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Long-term debt</td>
<td>$681,723</td>
<td>$737,010</td>
</tr>
<tr>
<td>Fair value of derivative instruments</td>
<td>28,028</td>
<td>30,290</td>
</tr>
<tr>
<td>Total noncurrent liabilities</td>
<td>709,751</td>
<td>767,300</td>
</tr>
<tr>
<td>Current liabilities:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Debt due within one year</td>
<td>50,885</td>
<td>49,130</td>
</tr>
<tr>
<td>Accrued interest</td>
<td>14,391</td>
<td>13,472</td>
</tr>
<tr>
<td>Accounts payable and accruals</td>
<td>6,035</td>
<td>7,000</td>
</tr>
<tr>
<td>Total current liabilities</td>
<td>71,311</td>
<td>69,602</td>
</tr>
<tr>
<td><strong>Total liabilities</strong></td>
<td>781,062</td>
<td>836,902</td>
</tr>
<tr>
<td><strong>NET POSITION</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Net investment in capital assets</td>
<td>(412,196)</td>
<td>(424,297)</td>
</tr>
<tr>
<td>Restricted</td>
<td>87,683</td>
<td>89,013</td>
</tr>
<tr>
<td>Unrestricted</td>
<td>(30,083)</td>
<td>(33,513)</td>
</tr>
<tr>
<td>Total net position</td>
<td>(354,596)</td>
<td>(368,797)</td>
</tr>
<tr>
<td><strong>Total liabilities and net position</strong></td>
<td>$426,466</td>
<td>$468,105</td>
</tr>
</tbody>
</table>
The following Statement of Revenues, Expenses and Changes in Position has been prepared by the Authority based upon audited financial statements of the Authority for the fiscal years ended June 30, 2014 and June 30, 2013.

Southern California Public Power Authority
Southern Transmission System Project
Statement of Revenues, Expenses and Changes in Net Position
(In thousands)

<table>
<thead>
<tr>
<th>Fiscal Year Ended June 30,</th>
<th>2014</th>
<th>2013 (as Restated)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operating revenues</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sales of transmission services</td>
<td>$117,170</td>
<td>$107,797</td>
</tr>
<tr>
<td>Total operating revenues</td>
<td>117,170</td>
<td>107,797</td>
</tr>
<tr>
<td>Operating expenses</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Operations and maintenance</td>
<td>35,269</td>
<td>25,333</td>
</tr>
<tr>
<td>Depreciation, depletion and amortization</td>
<td>22,754</td>
<td>22,750</td>
</tr>
<tr>
<td>Total operating expenses</td>
<td>58,023</td>
<td>48,083</td>
</tr>
<tr>
<td>Operating income</td>
<td>59,147</td>
<td>59,714</td>
</tr>
<tr>
<td>Non-operating revenues (expenses)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Investment and other income</td>
<td>903</td>
<td>5,717</td>
</tr>
<tr>
<td>Derivative gain</td>
<td>2,263</td>
<td>24,088</td>
</tr>
<tr>
<td>Debt expense</td>
<td>(48,112)</td>
<td>(46,458)</td>
</tr>
<tr>
<td>Net non-operating expenses</td>
<td>(44,946)</td>
<td>(16,653)</td>
</tr>
<tr>
<td>Change in net position</td>
<td>14,201</td>
<td>43,061</td>
</tr>
<tr>
<td>Net position – beginning of year</td>
<td>(368,797)</td>
<td>(407,074)</td>
</tr>
<tr>
<td>Cumulative effect of restatement</td>
<td>--</td>
<td>(4,784)</td>
</tr>
<tr>
<td>Net position – beginning of year as restated</td>
<td>--</td>
<td>(411,858)</td>
</tr>
<tr>
<td>Net position – end of year</td>
<td>$(354,596)</td>
<td>$(368,797)</td>
</tr>
</tbody>
</table>
THE PROJECT PARTICIPANTS

General

The Project Participants, each of which has executed a Capacity Acquisition Agreement and a Transmission Service Contract with the Authority, are the Department, the City of Anaheim, the City of Riverside, the City of Pasadena, the City of Burbank and the City of Glendale. Each Project Participant owns and operates an electric system for the distribution of electric energy to its retail customers. This section briefly describes the Project Participants with Transmission Service Shares exceeding 10% (i.e., the Department and the California cities of Anaheim and Riverside). For additional information concerning these three Project Participants and their respective electric systems, see Appendix A hereto.

The following table sets forth the Transmission Service Shares of each of the Project Participants with respect to Authority Capacity.

<table>
<thead>
<tr>
<th>Project Participants</th>
<th>Transmission Service Share</th>
</tr>
</thead>
<tbody>
<tr>
<td>Department of Water and Power of Los Angeles</td>
<td>59.534%</td>
</tr>
<tr>
<td>City of Anaheim</td>
<td>17.647</td>
</tr>
<tr>
<td>City of Riverside</td>
<td>10.164</td>
</tr>
<tr>
<td>City of Pasadena</td>
<td>5.883</td>
</tr>
<tr>
<td>City of Burbank</td>
<td>4.498</td>
</tr>
<tr>
<td>City of Glendale</td>
<td>2.274</td>
</tr>
<tr>
<td>Total</td>
<td>100.000%</td>
</tr>
</tbody>
</table>

The following members of the Authority are not Project Participants: IID and the California cities of Azusa, Banning, Cerritos, Colton and Vernon.

The Department

The Department is the largest municipal utility in the United States and is a proprietary department of the City of Los Angeles (the “City”). The Department controls its funds and is responsible for providing the electric and water requirements of its service area. The Department provides electric and water service almost entirely within the boundaries of the City. The City encompasses approximately 473 square miles and is populated by approximately 3.9 million residents.

Under The Charter of The City of Los Angeles (the “Charter”), the Board of Water and Power Commissioners (the “Board”) is granted the possession, management and control of the electric energy rights, lands, facilities and all other interests of the City related to the energy business (the “Power System”). The Board is composed of five members. Certain matters regarding the administration of the Department also require the approval of the Los Angeles City Council (the “City Council”).

While the retail rates for electric service (“Electric Rates”) are subject to approval by the City Council, the authority of the Board to impose and collect retail Electric Rates and charges for service from the Power System is not subject to the general regulatory jurisdiction of the California Public Utilities Commission (the “CPUC”) or any other California state or federal agency. At this time, neither the CPUC nor any other regulatory authority of the State of California nor the Federal Energy Regulatory Commission (“FERC”) approves such retail Electric Rates.
Although its retail Electric Rates are not subject to approval by any federal agency, the Department is subject to certain provisions of the Public Utilities Code and the Public Utility Regulatory Policies Act of 1978 (“PURPA”). PURPA applies to the purchase of the output of “qualified facilities” (“QFs”) at prices determined in accordance with PURPA. The Energy Policy Act of 2005 repealed the mandatory purchase obligation for utilities (including the Department) when FERC determines that the QFs have access to a competitive sales market and open access transmission.

Under federal law, FERC has the authority, under certain circumstances and pursuant to certain procedures, to order any utility (municipal or otherwise), including the Department, to provide transmission access to others at cost-based rates. FERC also has licensing authority over various hydroelectric facilities owned and operated by the Department.

**City of Anaheim**

The City of Anaheim is a municipal corporation existing under the laws of the State of California. The City of Anaheim owns and operates an electric public utility which provides electric service to virtually all the residential, commercial and industrial customers within the city limits, which encompass approximately 50 square miles. As of June 30, 2014, the principal facilities of Anaheim’s electric system consisted of transmission and distribution lines totaling 1,172 circuit miles, 12 distribution substations, Anaheim’s 10.04% ownership interest in Unit 4 of the San Juan Generating Station and Anaheim’s Kraemer combustion turbine power plant that began commercial operation in 1991 with a capacity of 48 MW in the winter and 46 MW in the summer. In 2011, the Authority’s Canyon Power Project, located in Anaheim, and to which Anaheim has a 100% entitlement share, was placed into full commercial operation. See also “SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY – Other Activities of the Authority – Canyon Power Project.”

Electric rates are established by the Anaheim City Council and are not subject to regulation by any California state agency. The City of Anaheim is also subject to certain ratemaking provisions of PURPA.

**City of Riverside**

The City of Riverside is a municipal corporation existing under the laws of the State of California. The City of Riverside owns and operates electric public utility facilities for its citizens, providing electric service to virtually all of the electric customers within the City of Riverside limits, which encompass approximately 81.5 square miles. The principal facilities of the City of Riverside’s electric system are sub-transmission and distribution lines aggregating approximately 1,425.6 circuit miles as of June 30, 2014, 14 substations, a 29.5 MW co-generation plant located in Corona, California purchased by Riverside in 2010, four power peaking plants with an aggregate capacity of 40 MW that began commercial operation in 2002 and a four-unit, 196 MW power plant and related transmission lines that achieved full commercial operation in 2011.

Electric rates for the City of Riverside are established by the Riverside City Board of Public Utilities, subject to approval of the Riverside City Council, and are not subject to regulation by any California state agency. The City of Riverside is also subject to certain ratemaking provisions of PURPA.
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 and storage alternatives, principally through more stringent renewables resource portfolio standard requirements. 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 also included 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 update 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. In addition, CARB approved a resolution at its October 25, 2013 board meeting that directs CARB’s executive officer to develop a plan for a post-2020 program, including a cost containment mechanism, before 2018.

The cap-and-trade program is being implemented in phases. The first phase of the program (January 1, 2013 to December 31, 2014) introduced a hard emissions cap covering 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 is expected to 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 currently scheduled for 2020 unless otherwise extended, as expected, through an act of the State legislature.

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 ISO 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 ISO markets, and those that sell into the ISO 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 will consider additional and updated offset protocols, including a new compliance offset protocol for rice cultivation practices, the adoption of which is currently expected to occur in mid-2015.

On April 25, 2014, CARB adopted various changes to the cap-and-trade program, including provisions relating to the electricity sector such as “safe harbor” provisions under the “resource shuffling” prohibition. These changes 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, although the first joint auction was delayed until November 25, 2014 in order to resolve certain technical issues. 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.

The Authority and the Project Participants are unable to predict at this time the full impact of the cap-and-trade program over the long-term on the Project Participants’ respective electric utilities or on the electric utility industry generally or whether any additional changes to the adopted program will be made. However, the Project Participants could be adversely affected in the future 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 allowances or other compliance instruments on the market to cover their emissions. The Project Participants may also be adversely affected depending on how the federal Clean Power Plan affects the State’s cap-and-trade program. See “OTHER FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY – Environmental Issues – Greenhouse Gas Regulations under the Clean Air Act” for a brief description of the federal Clean Power Plan.

**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 California Energy Commission (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 (“CO2”) 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 March 19, 2014, the CEC issued its Final Conclusions in the EPS proceeding. The CEC proposed 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 proposed 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 did not propose to lower the EPS. Further, by letter from the CPUC to the CEC, the CPUC expressed its view that the EPS not be lowered. A final regulatory package was unanimously adopted at the CEC’s June 18, 2014 business meeting. The adopted regulations had limited changes to the proposed POU reporting requirements. CEC staff have also since confirmed that the $2.5 million threshold applies to an individual investment by each utility – not the combined investment of all participants in a project. These changes and any future changes to the EPS regulations may impact the Project Participants.

**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 each Project Participant, 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 Project Participant 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 present 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 for POUs is given to the CEC and CARB, including authority to impose penalties. CARB is expected to complete a RPS enforcement penalties rulemaking by November 2015 for POUs.

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 on April 30, 2013, 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. Certain of the Project Participants are currently using bio-methane to generate electricity either in their local generation plants or at the Magnolia Power Plant and have obtained certification from the CEC to do so. Under these guidelines, utilities that procure bio-methane were required to reapply for certification of the generating facilities that use the bio-methane. The CEC is
expected to propose new amendments to the RPS enforcement procedures for POUs in December 2015 (or soon thereafter). CEC staff held a July 11, 2014 pre-rulemaking workshop to solicit comments on the following topics for proposed amendments: the Portfolio Content Category for POU-owned or procured distributed generation systems; the definitions of “retail sales” and “resale;” contract amendments and excess procurement; and dynamic transfer agreements. Project Participants submitted comments regarding the appropriate accounting for distributed generation resources by the July 28, 2014 comment deadline.

**Newly Introduced Climate Change Bills.** On January 5, 2015, Governor Jerry Brown proposed three major climate goals to be completed within the next 15 years: 1) increase from 33% to 50% California’s electricity derived from renewables; 2) reduce current petroleum use in cars and trucks by up to 50%; and 3) increase by 50% the efficiency of existing buildings and make heating fuels cleaner. Recently, a number of bills were introduced in the State Legislature that, if adopted, would, among other things, implement the climate goals announced by the Governor. As expected, the proposed bills would increase the State’s RPS from 33% to 50% (SB 350 and AB 645) and would require CARB to approve a statewide greenhouse gas emission limit to be achieved by 2050 that is equivalent to 80% below the 1990 level, as contemplated by Executive Order S-3-05, and would authorize CARB to adopt interim greenhouse gas emissions level targets to be achieved by 2030 and 2040 (SB 32). Another bill (SB 180) would require State agencies to update the EPS and expand application to secondary generation sources. The Authority and the Project Participants are analyzing newly introduced bills to assess what their full impact might be.

**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 has established programs in accordance with the requirements of the California Solar Initiative.

**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. The Authority 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’ respective electric utilities or the electric utility industry generally.

**Impact of Developments on the Project Participants**

The effect of the developments in the California energy markets described above on the Project Participants cannot be fully ascertained at this time. Also, volatility in energy prices in California may return due to a variety of factors that affect both the supply and demand for electric energy in the western
United States. These factors include, but are not limited to, the adequacy of generation resources to meet peak demands, the availability and cost of renewable energy, the impact of economy-wide 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 revenues of their respective electric systems from the sale (and purchase) of electric energy and, therefore, could materially affect each of the Project Participant’s financial condition. Each Project Participant undertakes resource planning and risk management activities and manages its resource portfolio to mitigate such price volatility and spot market rate exposure.

OTHER FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY

Federal Energy Legislation

Energy Policy Act of 2005. Under the federal Energy Policy Act of 2005 (“EPAct 2005”), FERC was given refund authority over POUs if they sell into short-term markets, like the ISO markets, and sell eight million MWhs or more of electric energy on an annual basis. In addition, 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 authorized FERC to issue permits to construct or modify transmission facilities located in a national interest electric transmission corridor if FERC determines that the statutory conditions are met. EPAct 2005 also required the creation of an electric reliability organization (“ERO”) to establish and enforce, under FERC supervision, mandatory reliability standards (“Reliability Standards”) to increase system reliability and minimize blackouts. Failure to comply with such Reliability Standards exposes a utility to significant fines and penalties by the ERO.

NERC Reliability Standards. EPAct 2005 required FERC to certify an ERO to develop mandatory and enforceable reliability standards, subject to FERC review and approval. The reliability standards apply to users, owners and operators of the Bulk-Power System, as more specifically set forth in each reliability standard. 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 WECC, may enforce the Reliability Standards, subject to FERC oversight, or FERC may independently enforce them. Potential monetary sanctions include fines of up to $1 million per violation per day. 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.

Other Legislation. Congress has considered and is considering numerous bills addressing domestic energy policies and various environmental matters, including bills relating to energy supplies and development (such as a federal energy efficiency standard and expedited permitting for natural gas drilling projects), global warming, physical and cyber security and water quality. Many of these bills, if enacted into law, could have a material impact on the Authority and the Project Participants and the electric utility industry generally. 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 cyber security is also possible. However, the Authority and the Project Participants are unable to predict the outcome or potential impacts of any possible legislation.

**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 Authority or Project Participants 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.

**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, CO₂, 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 determined that it was authorized to issue regulations limiting CO₂ emissions 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 regulates greenhouse gas emissions from large stationary sources, including electric generating facilities, if the sources emit more than the specified threshold levels of tons per year of CO₂. 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 repeal 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 CO₂ 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 CO₂ emissions from new natural gas-fired units to 1,000 pounds of CO₂ per MWh for larger units and 1,100 pounds of CO₂ per MWh for smaller units. These emission limits are based on the use of natural gas combined cycle technology. CO₂ emissions from new coal-fired units would be restricted to 1,100 pounds of CO₂ 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 CO₂ 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 expected to be finalized in June 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 both existing and modified or reconstructed power plants as contemplated by the Presidential Memorandum. The proposed rule is designed to reduce CO₂ emissions from the power sector by 30% on average nationwide by 2030, as compared to 2012 levels. Under the proposal, the EPA will set different interim (2024) and final (2030) emissions targets for each state based on overall CO₂ emissions and the amount of electricity generated in the state. The emissions target for California for 2030 is proposed to be 537 pounds of CO₂ per MWh, representing a reduction of approximately 23.1% from estimated 2012 emissions levels of 698 pounds of CO₂ per MWh. States will have one year after finalization of the rule (until June 2016 under the current schedule) to design their own state implementation plans to reach the emissions target or may request an extension through 2018 for states working on multi-state plans. Interim standards would apply from 2020 to 2029, with final standards taking effect in 2030. It is proposed that state emission targets may be met in a combination of ways, including through a “Best System of Emissions Reduction,” which may include coal plant efficiency upgrades, switching from coal to natural gas, and by improving energy efficiency or promoting renewable energy. In the event a state fails to develop a satisfactory implementation plan, the EPA may impose a federal implementation plan instead.

The Authority submitted comments to the EPA on November 25, 2014 and joined in support of comments also filed jointly by the “California Utilities” prior to the December 1, 2014 comment deadline. The Authority’s comments outlined potential issues and offered recommendations on how to improve the proposed rule so as not to compromise electric reliability for customers.

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 CO₂ per MWh. Smaller coal-fired units would be required to meet an emission limit of 2,100 pounds of CO₂ per MWh. These emissions 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 CO₂ 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 emissions limit of 1,000 pounds of CO₂ per MWh. Smaller facilities would be required to meet an emissions limit of 1,100 pounds of CO₂ per MWh.

The proposed rules for existing, and modified or reconstructed, power plants were published in the Federal Register on June 18, 2014; comments on the proposed rules were accepted until December 1, 2014 and October 16, 2014, respectively. The EPA has indicated that it intends to finalize the “Clean Power Plan” rules in mid-summer of 2015. FERC is conducting a number of conferences through March 2015 to assess potential reliability impacts from the proposed rules. EPA officials have been participating in these conferences.

A number of lawsuits have been filed challenging the proposed rules and 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 any other approach that may be adopted).

The Authority 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 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 the EPA 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 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. On November 26, 2014, the EPA proposed to increase the stringency of the NAAQS for ozone by lowering the existing ozone standard of 75 parts per billion (“ppb”) to between 65 and 70 ppb, although the EPA is also soliciting public comment on a standard as low as 60 ppb. The new proposed rule was published in the Federal Register on December 17, 2014. Comments on the proposed rule will be accepted until March 17, 2015. A final rule is expected to be issued in October 2015. On December 18, 2014, the EPA issued a final rule making initial area designations for the 2012 NAAQS for fine particulate matter (“PM2.5”), designating 14 areas in six states as non-attainment, including the Los Angeles – San Bernardino Counties and the Los Angeles – South Coast Air Basin. These PM2.5 designations will be effective on April 15, 2015.

**Mercury and Air Toxics Standards.** 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 Mercury and Air Toxics Standards (“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 oxide. 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. On November 25, 2014, the United States Supreme Court agreed to review the MATS rule following the filing of petitions for writ of certiorari from 23 states and industry groups; a ruling is expected in June 2015. Certain of the Project Participants purchase power from coal-fired power stations that may be affected by these new rules, and in the event the MATS standards are ultimately upheld, such Project Participants may be exposed to increased costs.

**Regulation of Coal Combustion Residuals.** On June 21, 2010, the EPA proposed to regulate coal combustion residuals (“CCR”) 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 released its final CCR rule on December 19, 2014, adopting the industry-preferred alternative regulation classifying CCRs as nonhazardous solid waste.

**Regulation of Cooling Water Intake Structures.** On April 20, 2011, the EPA proposed to regulate cooling water intake structures at certain existing power plants in order to reduce the number of fish and other aquatic organisms that are trapped against intake screens or drawn into the generating unit. The EPA proposed to require modified intake screens that would capture and safely return fish to water bodies, or require the facility’s water intake velocity to be reduced, thus allowing fish to move away from intake structures. The best technology to reduce entrainment would be determined on a site-specific basis. A final regulation was released by the EPA on May 16, 2014 and became effective on October 14, 2014. The regulation is expected to increase the cost of power that the Project Participants purchase from certain fossil fuel-fired units.

**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 CCRs. 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. The proposed regulation could increase the cost of power that the Project Participants purchase from steam electric power plants.

The Authority and the Project Participants are unable to predict the outcome of the legal and legislative challenges to the EPA’s endangerment finding and subsequent rulemaking, or the effect that any future final rules promulgated by the EPA regulating electric generating units and other stationary sources would have on the Authority’s projects or the Project Participants or their respective electric systems.

**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 or potential new energy storage requirements), (b) changes resulting from conservation and demand-side management programs on the timing and use of electric energy, (c) 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.

The Authority is unable to predict what impact such factors will have on the business operations and financial condition of the Project Participants, but the impact could be significant. This Official Statement 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 2015 Series C Subordinate Bonds should obtain and review such information.

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 most of 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 cities’ general fund revenues, cities could seek to increase the transfers from the electric utilities of those cities to the cities’ general fund. See, however, “Proposition 26” below.

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, electric service charges (which are expressly exempted from the provisions of Article XIIID) may be subject to the initiative provisions of Article XIIIC, thereby subjecting such fees and charges imposed by each Project Participant to reduction by the electorate. The Authority believes that even if the electric rates of any Project Participant are subject to the initiative power, under Article XIIIC or otherwise, its electorate would be precluded from reducing electric rates and charges in a manner materially and adversely affecting the payment of the 2015 Series C Subordinate Bonds by virtue of the “impairment of contracts clauses” of the United States and California Constitutions.
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 in California Constitution Articles XIIIA, XIIIC and XIIID pursuant to Proposition 13, approved in 1978, Proposition 218, approved in 1996, 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. The Authority and the Project Participants are unable to predict at this time how Proposition 26 will be interpreted by the courts or what its ultimate impact will be.

Other Initiatives

Articles XIIIA, XIIIC and XIIID were adopted as measures that qualified for the ballot pursuant to California’s initiative process. From time to time, including presently, other initiatives have been, and could be, proposed, and if qualified for the ballot, could be adopted affecting the Authority’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 predicted by the Authority or the Project Participants.

LITIGATION

At the time of delivery of the 2015 Series C Subordinate Bonds, an authorized officer of the Authority will certify that, to the knowledge of such officer, there is no litigation or other proceeding pending or threatened in any court, agency or other administrative body (either State of California or federal) restraining or enjoining the issuance, sale or delivery of the 2015 Series C Subordinate Bonds or the collection of Pledged Revenues, or in any way questioning or affecting (i) the proceedings under which the 2015 Series C Subordinate Bonds are to be issued, (ii) the validity of any provision of the 2015 Series C Subordinate Bonds, the Senior Indenture or the 2015 Series C Subordinated Indenture, (iii) the pledge by the Authority under the 2015 Series C Subordinated Indenture, (iv) the validity or enforceability of the Transmission Service Contracts, (v) the legal existence of the Authority or the title to office of the present officers of the Authority, or (vi) the authority of the Authority to undertake the Southern Transmission Project.

For a description of litigation relating to IPA, see “APPENDIX A – THE PROJECT PARTICIPANTS WITH THE LARGEST ENTITLEMENT SHARES – THE DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES – LITIGATION – Dairy Cow Litigation” and “APPENDIX B – INTERMOUNTAIN POWER AGENCY AND INTERMOUNTAIN POWER PROJECT – INTERMOUNTAIN POWER PROJECT – Fuel Supply.” If IPA or the Department, as Project Manager and Operating Agent for IPP, is required to pay any settlement amount or any judgment relating to such litigation, then the Project Participants, as participants in IPP, may be obligated to pay a substantial portion of those costs in accordance with their entitlement shares in IPP. In addition, the
Authority is also a defendant in the litigation described in Appendix A under the caption “THE PROJECT PARTICIPANTS WITH THE LARGEST ENTITLEMENT SHARES – THE DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES – LITIGATION – Dairy Cow Litigation.” If the Authority is required to pay any settlement amount or any judgment relating to such litigation, then the Project Participants may be obligated to pay such costs based upon their Transmission Service Shares.

**TAX MATTERS**

The Internal Revenue Code of 1986 (the “Code”) imposes certain requirements that must be met subsequent to the issuance and delivery of the 2015 Series C Subordinate Bonds for interest thereon to be and remain excluded pursuant to section 103(a) of the Code from the gross income of the owners thereof for federal income tax purposes. Noncompliance with such requirements could cause the interest on the 2015 Series C Subordinate Bonds to be included in the gross income of the owners thereof for federal income tax purposes retroactive to the date of issue of the 2015 Series C Subordinate Bonds. The Authority has covenanted in the 2015 Series C Subordinated Indenture, and each Project Participant has covenanted in its Transmission Service Contract, not to take any action or omit to take any action which, if taken or omitted, respectively, would adversely affect the exclusion of the interest on the 2015 Series C Subordinate Bonds from the gross income of the owners thereof for federal income tax purposes.

In the opinion of Norton Rose Fulbright US LLP, Los Angeles, California, and Curls Bartling P.C., Oakland, California, Co-Bond Counsel, under existing law interest on the 2015 Series C Subordinate Bonds is exempt from personal income taxes of the State of California and, assuming compliance with the aforementioned covenants, interest on the 2015 Series C Subordinate Bonds is excluded pursuant to section 103(a) of the Code from the gross income of the owners thereof for federal income tax purposes. Co-Bond Counsel are of the further opinion that the 2015 Series C Subordinate Bonds are not “specified private activity bonds” within the meaning of section 57(a)(5) of the Code and, therefore, interest on the 2015 Series C Subordinate Bonds is not treated as an item of tax preference for purposes of computing the alternative minimum tax imposed by section 55 of the Code; however, the receipt or accrual of interest on the 2015 Series C Subordinate Bonds owned by a corporation may affect the computation of its alternative minimum taxable income. A corporation’s alternative minimum taxable income is the basis on which the alternative minimum tax imposed by section 55 of the Code is computed. In rendering the foregoing opinions, Co-Bond Counsel will rely upon representations and certifications of the Authority and the Project Participants made in certificates, dated the date of delivery of the 2015 Series C Subordinate Bonds, pertaining to the use, expenditure, and investment of the proceeds of the 2015 Series C Subordinate Bonds.

The purchase price of certain 2015 Series C Subordinate Bonds (the “Premium Bonds”) paid by an owner may be greater than the amount payable on such Bonds at maturity. An amount equal to the excess of a purchaser’s tax basis in a Premium Bond over the amount payable at maturity constitutes premium to such purchaser. The basis for federal income tax purposes of a Premium Bond in the hands of such purchaser must be reduced each year by the amortizable bond premium, although no federal income tax deduction is allowed as a result of such reduction in basis for amortizable bond premium. Such reduction in basis will increase the amount of any gain (or decrease the amount of any loss) to be recognized for federal income tax purposes upon a sale or other taxable disposition of a Premium Bond. The amount of premium that is amortizable each year by a purchaser is determined by using such purchaser’s yield to maturity (or, in some cases with respect to a callable bond, the yield based on a call date that results in the lowest yield on the bond). Purchasers of the Premium Bonds should consult with their own tax advisors with respect to the determination of amortizable bond premium on Premium Bonds for federal income tax purposes and with respect to the state and local tax consequences of owning and disposing of Premium Bonds.
Co-Bond Counsel have not undertaken to advise in the future whether any events after the date of issuance of the 2015 Series C Subordinate Bonds may affect the tax status of interest on the 2015 Series C Subordinate Bonds or the tax consequences of the ownership of the 2015 Series C Subordinate Bonds. No assurance can be given that pending or future legislation, or amendments to the Code, if enacted into law, or any proposed legislation or amendments to the Code, will not contain provisions that could directly or indirectly reduce the benefit of the exemption of interest on the 2015 Series C Subordinate Bonds from personal income taxation by the State of California or of the exclusion of the interest on the 2015 Series C Subordinate Bonds from the gross income of the owners thereof for federal income tax purposes. Furthermore, Co-Bond Counsel express no opinion as to any federal, state or local tax law consequences with respect to the 2015 Series C Subordinate Bonds, or the interest thereon, if any action is taken with respect to the 2015 Series C Subordinate Bonds or the proceeds thereof upon the advice or approval of other bond counsel.

Although Co-Bond Counsel are of the opinion that interest on the 2015 Series C Subordinate Bonds is exempt from California personal income tax and that interest on the 2015 Series C Subordinate Bonds is excluded from the gross income of the owners thereof for federal income tax purposes, an owner’s federal, state or local tax liability may otherwise be affected by the ownership or disposition of such owner’s 2015 Series C Subordinate Bonds. The nature and extent of these other tax consequences will depend upon the owner’s other items of income or deduction. Without limiting the generality of the foregoing, prospective purchasers of the 2015 Series C Subordinate Bonds should be aware that (i) section 265 of the Code denies a deduction for interest on indebtedness incurred or continued to purchase or carry the 2015 Series C Subordinate Bonds, and the Code contains additional limitations on interest deductions applicable to financial institutions that own tax-exempt obligations (such as the 2015 Series C Subordinate Bonds), (ii) with respect to insurance companies subject to the tax imposed by section 831 of the Code, section 832(b)(5)(B)(i) reduces the deduction for loss reserves by 15% of the sum of certain items, including interest on the 2015 Series C Subordinate Bonds, (iii) interest on the 2015 Series C Subordinate Bonds earned by certain foreign corporations doing business in the United States could be subject to a branch profits tax imposed by section 884 of the Code, (iv) passive investment income, including interest on the 2015 Series C Subordinate Bonds, may be subject to federal income taxation under section 1375 of the Code for Subchapter S corporations that have Subchapter C earnings and profits at the close of the taxable year if greater than 25% of the gross receipts of such Subchapter S corporation is passive investment income, (v) section 86 of the Code requires recipients of certain Social Security and certain Railroad Retirement benefits to take into account, in determining the taxability of such benefits, the receipt or accrual of interest on the 2015 Series C Subordinate Bonds, and (vi) under section 32(i) of the Code, receipt of investment income, including interest on the 2015 Series C Subordinate Bonds, may disqualify the recipient thereof from obtaining the earned income credit. Co-Bond Counsel have expressed no opinion regarding any such other tax consequences.

Co-Bond Counsel’s opinion is not a guarantee of a result, but represents their legal judgment based upon their review of existing statutes, regulations, published rulings and court decisions and the covenants of the Authority and the Project Participants described above. No ruling has been sought from the Internal Revenue Service (the “Service”) with respect to the matters addressed in the opinion of Co-Bond Counsel, and Co Bond Counsel’s opinion is not binding on the Service. The Service has an ongoing program of auditing the tax-exempt status of the interest on municipal obligations. If an audit of the 2015 Series C Subordinate Bonds is commenced, under current procedures the Service is likely to treat the Authority as the “taxpayer,” and the owners of the 2015 Series C Subordinate Bonds would have no right to participate in the audit process. In responding to or defending an audit of the tax-exempt status of the interest on the 2015 Series C Subordinate Bonds, the Authority may have different or conflicting interests from the owners of the 2015 Series C Subordinate Bonds. Public awareness of any future audit of the 2015 Series C Subordinate Bonds could adversely affect the value and liquidity of the 2015 Series C Subordinate Bonds during the pendency of the audit, regardless of the ultimate outcome.
Existing law may change so as to reduce or eliminate the benefit to holders of the 2015 Series C Subordinate Bonds of the exclusion of interest thereon from gross income for federal income tax purposes. Proposed legislative or administrative action, whether or not taken, could also affect the value and marketability of the 2015 Series C Subordinate Bonds. Prospective purchasers of the 2015 Series C Subordinate Bonds should consult with their own tax advisors with respect to any proposed changes in tax law.

**RATINGS**

Standard & Poor’s Ratings Service, a Standard & Poor’s Financial Services LLC business, and Fitch Ratings, Inc. have assigned the 2015 Series C Subordinate Bonds the municipal bond credit ratings of “AA-” and “AA-,” respectively. Each such rating should be evaluated independently of any other rating. Each such credit rating reflects only the view of the organization furnishing the rating and any desired explanation of the significance of such credit rating should be obtained from such rating agency. No application has been made to any other rating agency in order to obtain additional ratings on the 2015 Series C Subordinate Bonds.

The above described ratings are not a recommendation to buy, sell or hold the 2015 Series C Subordinate Bonds, and either such rating may be subject to revision or withdrawal at any time by the rating agency assigning such rating. The Authority and the Underwriters undertake no responsibility either to bring to the attention of the owners of the 2015 Series C Subordinate Bonds the revision or the withdrawal of any rating obtained or to oppose any such downward revision or withdrawal. Any downward revision or withdrawal of a rating may have an adverse effect on the market prices of the 2015 Series C Subordinate Bonds.

**UNDERWRITING**

The 2015 Series C Subordinate Bonds will be purchased jointly and severally for reoffering by the Underwriters, at an aggregate purchase price of $142,065,525.23, representing the par amount of the 2015 Series C Subordinate Bonds of $116,535,000, plus original issue premium of $25,700,951.75, and less an Underwriters’ discount of $170,426.52. The Underwriters will be obligated to purchase all of the 2015 Series C Subordinate Bonds if any of the 2015 Series C Subordinate Bonds are purchased.

Morgan Stanley, parent company of Morgan Stanley & Co. LLC, an underwriter of the 2015 Series C Bonds, has entered into a retail distribution arrangement with its affiliate Morgan Stanley Smith Barney LLC. As part of the distribution arrangement, Morgan Stanley & Co. LLC may distribute municipal securities to retail investors through the financial advisor network of Morgan Stanley Smith Barney LLC. As part of this arrangement, Morgan Stanley & Co. LLC may compensate Morgan Stanley Smith Barney LLC for its selling efforts with respect to the 2015 Series C Bonds.

The Underwriters may offer and sell the 2015 Series C Subordinate Bonds to certain dealers (including dealers depositing 2015 Series C Subordinate Bonds into investment trusts) and others at prices lower than the respective public offering prices stated or derived from information stated on the inside cover page hereof. The initial public offering prices may be changed from time to time by the Underwriters.

**FINANCIAL ADVISOR**

The Authority has retained Public Financial Management, Inc., Los Angeles, California, as financial advisor (the “Financial Advisor”) in connection with the issuance of the 2015 Series C Subordinate Bonds. The Financial Advisor has not undertaken to make an independent verification or to
assume responsibility for the accuracy, completeness, or fairness of the information contained in this Official Statement. The Financial Advisor is an independent financial advisory firm and is not engaged in the business of underwriting, trading or distributing municipal securities or other public securities. The payment of the fees of the Financial Advisor is contingent upon the issuance and delivery of the 2015 Series C Subordinate Bonds.

CERTAIN LEGAL MATTERS

Certain legal matters in connection with the authorization and issuance of the 2015 Series C Subordinate Bonds are subject to the approval of Norton Rose Fulbright US LLP, Los Angeles, California, and Curls Bartling P.C., Oakland, California, Co-Bond Counsel. The form of opinion that Co-Bond Counsel propose to render with respect to the 2015 Series C Subordinate Bonds is attached as Appendix E hereto. Certain other legal matters with respect to the Authority will be passed upon by its General Counsel, Richard J. Morillo, Esq. Certain legal matters will be passed upon for the Underwriters by their counsel, Sidley Austin LLP, San Francisco, California.

CERTAIN RELATIONSHIPS

The Underwriters and their respective affiliates are full service financial institutions engaged in various activities, which may include securities trading, commercial and investment banking, financial advisory, investment management, principal investment, hedging, financing and brokerage activities. The Underwriters and their respective affiliates have, from time to time, performed, and may in the future perform, various investment banking services for the Authority, for which they received or will receive customary fees and expenses.

In addition, in the ordinary course of sales, trading, brokerage and financing activities, the Underwriters may at any time hold long or short positions, and may trade or otherwise effect transactions, for their own accounts or the accounts of customers, in debt or equity securities and financial instruments or bank loans, as applicable, of the Authority, the Project Participants and other governmental entities and utilities. In connection with these activities and the provision of other services, certain of the Underwriters may be or become creditors of such entities. In addition, certain of the Underwriters, or their affiliates, currently and may in the future serve as commercial paper dealers, remarketing agents or providers of credit enhancement or liquidity facilities for variable rate obligations issued by, or as interest rate swap providers to, governmental entities and utilities, including, in some cases, the Authority.

VERIFICATION OF MATHEMATICAL COMPUTATIONS

The accuracy of the mathematical computations of (i) the adequacy of the principal of and interest on the Defeasance Obligations and cash, if any, to be held in the Escrow Fund to pay interest on the Refunded Bonds as the same shall become due on and prior to July 1, 2018 and to pay on July 1, 2018, the redemption date of the Refunded Bonds, the redemption price therefor and (ii) the yield on the 2015 Series C Subordinate Bonds and the yield on the Defeasance Obligations purchased with a portion of the proceeds of the sale of the 2015 Series C Subordinate Bonds and other available funds of the Authority, which will be used in part by Co-Bond Counsel in concluding that the interest on the 2015 Series C Subordinate Bonds is excluded from gross income for federal income tax purposes under present laws, including applicable provisions of the Code, existing court rulings, regulations and Internal Revenue Service rulings, will be verified by an independent arbitrage consultant selected by the Authority.
CONTINUING DISCLOSURE UNDERTAKING FOR THE 
2015 SERIES C SUBORDINATE BONDS

Pursuant to the Continuing Disclosure Resolution of the Authority’s Board of Directors, the Authority has agreed for the benefit of the registered owner and the Beneficial Owners (as defined in Appendix D hereto) of the 2015 Series C Subordinate Bonds to provide certain financial information and operating data relating to the Authority, the Department and the California cities of Anaheim and Riverside by not later than six months after the end of each of the Authority’s fiscal years (presently, by each December 31) commencing with fiscal year 2014-15 (the “Annual Report”) and to provide notices of the occurrence of certain enumerated events with respect to the 2015 Series C Subordinate Bonds. The Annual Report will be filed by or on behalf of the Authority with the Municipal Securities Rulemaking Board (“MSRB”) through the MSRB’s Electronic Municipal Market Access (“EMMA”) system. The notices of such events will also be filed by or on behalf of the Authority with the MSRB also through the EMMA system. The specific nature of the information to be contained in the Annual Report and the notices of events is set forth in the form of the Continuing Disclosure Resolution which is included in its entirety in Appendix D hereto. The Authority’s continuing disclosure undertaking has been made in order to assist the Underwriters in complying with Securities and Exchange Commission Rule 15c2-12.

As of the date hereof, the Authority is in compliance in all material respects with its continuing disclosure undertakings for the last five years. Filings through EMMA are linked to a particular issue of obligations by CUSIP numbers. The Authority currently files 16 different annual reports each year for various projects for which it has issued revenue bonds. In the last five years, three of the annual reports, for fiscal years ended June 30, 2011 or, as applicable, June 30, 2012, were not appropriately linked to certain CUSIP numbers. The Authority has since linked the applicable filings to these CUSIP numbers. In addition, the annual financial information filed by the Authority for fiscal years ended June 30, 2011 through June 30, 2013 in connection with one of the 16 annual reports inadvertently omitted a sentence regarding the amount of gas sold by the Authority to project participants. An amended filing has been posted with EMMA to address this omission. Further, the annual financial information filed by the Authority for fiscal years ended June 30, 2012 and June 30, 2013 in connection with one of the 16 annual reports inadvertently omitted certain operating statistics for the related project. An amended filing has been posted with EMMA to correct this omission. Lastly, rating changes in connection with revenue bonds related to one of the 16 projects were inadvertently not updated. A filing has been posted with EMMA to update the ratings. None of the items described in this paragraph relates to the continuing disclosure undertakings for the Authority’s revenue bonds issued in connection with the Southern Transmission Project. The Authority believes it has established processes to ensure it will continue to comply in all material respects with its continuing disclosure undertakings in the future.

AVAILABLE INFORMATION

Copies of the Authority’s most recent audited financial statements and Annual Report, and copies of the forms of the Transmission Service Contracts, the Capacity Acquisition Agreements, the STS Agreement, the IPP Power Sales Contracts, the Agency Agreement, the Senior Indenture, the Prior Subordinated Indentures and the 2015 Series C Subordinated Indenture are available from the Authority, 1160 Nicole Court, Glendora, California 91740.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

By /s/ Fred H. Mason
President

50
APPENDIX A

THE PROJECT PARTICIPANTS WITH THE LARGEST ENTITLEMENT SHARES

The information contained in this Appendix has been furnished to Southern California Public Power Authority by the Project Participants with Transmission Service Shares exceeding 6%. This Appendix presents information as of the respective dates set forth herein, and the applicable Project Participant makes no representations regarding the accuracy of this information subsequent to such dates. Neither the Authority nor any other Project Participant makes any representation regarding the accuracy of the information contained in this Appendix.

THE DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES

General

The Department of Water and Power of the City of Los Angeles (the “Department”) is the largest municipal utility in the United States and is a proprietary department of the City of Los Angeles (the “City”). Control of Power System assets and funds is vested with the Board, whose actions are subject to review by the City Council. The Department is responsible for providing the electric and water requirements of its service area. The Department provides electric and water service almost entirely within the boundaries of the City. The City encompasses approximately 473 square miles and is populated by approximately 3.9 million residents.

Department operations began in the early years of the twentieth century. The first Board of Power Commissioners was established in 1902. Nine years later, the responsibilities for the provision of electricity and water within the City were given to the Los Angeles Department of Public Service (the “Department of Public Service”). The Department of Public Service was superseded in 1925 with passage of the 1925 Charter and the creation of the Department. The Department now operates under a new charter that became effective July 1, 2000 (the “Charter”). The operations and finances of the water system (the “Water System”) are separate from those of the power system (the “Power System”).

A copy of the most recent official statement or offering memorandum prepared by the Department for the issuance of securities for its Power System may be obtained from Mario C. Ignacio, CFA, Chief Accounting Employee of the Department of Water and Power of the City of Los Angeles, 111 North Hope Street, Room 465, Los Angeles, California 90012.

Charter Provisions

Pursuant to the Charter, the Board of Water and Power Commissioners of the City of Los Angeles (the “Board”) is the governing body of the Department and the General Manager of the Department (the “General Manager”) administers the affairs of the Department.

The Charter provides that all revenue from every source collected by the Department in connection with its possession, management and control of the Power System is to be deposited in the Power Revenue Fund. The Charter further provides that the Board controls the money in the Power Revenue Fund and makes provision for the issuance of Department bonds, notes and other evidences of indebtedness payable out of the Power Revenue Fund. The procedure relating to the authorization of the issuance of bonds is governed by Section 609 of the Charter.

Section 245 of the Charter provides that, with certain exceptions, actions of City commissions and boards (“Board Action”), including the Board, do not become final until five consecutive City Council meetings convened in regular session have passed. During those five City Council meetings, the City Council may, on a two-thirds vote, take up the Board Action. If the Board Action is taken up, the City Council may approve or veto the Board Action within 21 calendar days of taking up the Board Action.
Action. If the City Council takes no action to assert jurisdiction over the Board Action during those five meetings, the Board Action becomes final at the end of such period.

**Board of Water and Power Commissioners**

Under the Charter, the Board is granted the possession, management and control of the Power System. Pursuant to the Charter, the Board also has the power and duty to make and enforce all necessary rules and regulations governing the construction, maintenance, operation, connection to and use of the Power System and to acquire, construct, extend, maintain and operate all improvements, utilities, structures and facilities the Board deems necessary or convenient for purposes of the Department. The Mayor of the City appoints, and the City Council confirms the appointment of, members of the Board. The Board is traditionally selected from among prominent business, professional and civic leaders in the City. The members of the Board serve with only nominal compensation. Certain matters regarding the administration of the Department also require the approval of the City Council.

The Board is composed of five members. The current members of the Board are:

**MEL LEVINE, President.** Mr. Levine was appointed to the Board by Mayor Eric Garcetti and confirmed by the City Council on September 11, 2013. He assumed the position of President of the Board on October 1, 2013. Mr. Levine served as a member of the United States Congress from 1983-1993 and as a member of the California Assembly from 1977-1982. He was a partner at the law firm of Gibson, Dunn & Crutcher from 1993-2012 and continues as an Of Counsel to the firm. Mr. Levine chairs the Advisory Board of the Center on Public Diplomacy at USC’s Annenberg School, is a member of the Advisory Board of the Goldman School of Public Policy at the University of California at Berkeley and is a director of the Pacific Council on International Policy. He has served as U.S. Chair of the U.S.-Israel-Palestinian “Anti-Incemement” committee established by the Wye Plantation peace agreement, as a Presidential appointee to the United States Holocaust Memorial Council, as a U.S. government appointee to the U.S.-Israel Science and Technology Advisory Commission, as President of the American Friends of the (Yitzhak) Rabin Center in Israel, and as Board Chair of the Los Angeles Police Foundation. Mr. Levine holds a law degree from Harvard University, a master’s degree in public affairs from Princeton University and a bachelor’s degree from the University of California at Berkeley.

**WILLIAM W. FUNDERBURK, JR., Vice-President.** Mr. Funderburk was appointed to the Board by Mayor Eric Garcetti and confirmed by the City Council on September 11, 2013. He assumed the position of Vice President of the Board on October 1, 2013. Mr. Funderburk is a partner at the law firm of Castellon & Funderburk, handling government initiated and private party enforcement litigation and regulatory compliance. He has served on the National Phase II Storm Water Advisory Board, the California Environmental Liability Insurance Task Force, the Environmental Justice Legal Task Force, and the Los Angeles Environmental Crimes Sentencing Task Force. Mr. Funderburk also has served on the boards of the EnvironMentors Project, Wildlife on Wheels, and the Greater Wilshire Neighborhood Council. He holds a law degree from Georgetown University Law Center and a bachelor’s degree from Yale University.

**JILL BANKS BARAD, Commissioner.** Ms. Barad was appointed to the Board by Mayor Eric Garcetti and confirmed by the City Council on September 11, 2013. She owns Jill Barad & Associates, a political consulting, public relations and government affairs firm. Ms. Barad serves on the Sherman Oaks Neighborhood Council, the Valley Alliance of Neighborhood Councils, and the Valley Industry and Commerce Association. Previously, she chaired Mayor Tom Bradley’s Advisory Committee on Education and served on the Citizens Advisory Committee on Student Integration and has taught political public relations, media and fundraising at the University of California at Los Angeles. Ms. Barad founded The Open School to create the first community-initiated magnet school in the Los Angeles Unified School District, which went on to become the first charter school in California. She holds a bachelor’s degree from Temple University.
MICHAEL F. FLEMING, Commissioner. Mr. Fleming was appointed to the Board by Mayor Eric Garcetti and confirmed by the City Council on September 11, 2013. He is Executive Director of The David Bohnett Foundation, a charitable grant making foundation whose goal is to improve society through social justice and civic activism. Mr. Fleming also teaches undergraduate humanities and graduate level public policy courses at the University of California at Los Angeles. He began his career as a producer at WGBH-TV, the Boston PBS station and is Chair of the Board of Directors of the KCRW Foundation. Mr. Fleming has served as President of the East Los Angeles Area Planning Commission and as a commissioner of the Board of the Los Angeles Convention Center. He holds a bachelor’s degree from Colorado College and was a Victory Fellow (now Bohnett Fellow) at Harvard University’s John F. Kennedy School of Government.

CHRISTINA E. NOONAN, Commissioner. Ms. Noonan was originally appointed to the Board by then-Mayor Antonio Villaraigosa and confirmed by the City Council on August 10, 2010. She was reappointed to the Board by Mayor Eric Garcetti and re-confirmed by the City Council on September 11, 2013. Ms. Noonan is a Senior Vice President of Jones Lang LaSalle’s Los Angeles office, where she develops strategic real estate solutions for her clients by assessing the viability of lease renegotiations, relocations, consolidations, dispositions, building sales and acquisition alternatives. Before being appointed to the Board, Ms. Noonan served on the Los Angeles Convention Center Board as its President. She is a member of Commercial Real Estate Women, the World Affairs Council and Allen Matkins’s Women at the Top – Real Estate Roundtable. Ms. Noonan was appointed by then-Mayor Villaraigosa to the Office of Public Safety Oversight Committee for the City. She also served on the Board of LA, Inc. and on the Mayor’s Trade Advisory Council to promote international business in the City. Ms. Noonan is involved in many charities, including Aviva, Phoenix House, ALS Association, and she has mentored teens through the Fulfillment Fund organization. Ms. Noonan holds a degree in Psychology from the University of California at Santa Cruz and graduated with Highest Honors.

Management of the Department

The management and operation of the Department are administered under the direction of the General Manager. The Power System is directed by the Department’s Senior Assistant General Manager – Power System. The Department’s financial affairs are supervised by the Department’s Chief Financial Officer. Legal counsel is provided to the Department by the Office of the City Attorney of the City of Los Angeles.

Below are brief biographies of the Department’s General Manager, Ms. Marcie L. Edwards and other members of the senior management team for the Power System:

MARCIE L. EDWARDS. Ms. Edwards is a 37 year veteran of the utility industry, and presently serves as the General Manager of the Department. Ms. Edwards assumed her current position on March 3, 2014. Ms. Edwards served as the City Manager of the City of Anaheim from May 2013 until February 2014. Prior to her appointment as City Manager, Ms. Edwards was the General Manager of the City of Anaheim’s municipal water and electric utility from January 2001 to May 2013. Prior to her job as Utility General Manager in the City of Anaheim, Ms. Edwards was an Assistant General Manager at the Department with experience in oversight of electric operations, engineering, transmission line construction and maintenance, and overall utility customer service. Ms. Edwards managed a $1.3 billion budget and approximately 3,000 employees in two major divisions. Ms. Edwards is a founding board member of the Association of Women in Water, Energy, and Environment. Ms. Edwards is a past board member of the Anaheim Community Foundation, a past regional member of the National Board of the American Public Power Association (the “APPA”), past President of the California Municipal Utilities Association (the “CMUA”), past Vice Chair of the Metropolitan Water District Board, and past President of the Southern California Public Power Authority. A past Governor on the California Independent System Operator Board, Ms. Edwards also served as interim CEO of that agency in 2004, and, in that role, assisted in avoiding statewide power outages during the California energy crisis. Ms. Edwards
received both her bachelor’s degree in organizational management, as well as her master’s degree in public administration from the University of La Verne.

DAVID H. WRIGHT, Senior Assistant General Manager – Power System. Mr. Wright assumed the position of Senior Assistant Manager for the Power System on February 2, 2015. Mr. Wright has spent 26 years in the public utilities industry, including five years as Utilities Assistant Director of Finance and Administration, five years as Utilities Deputy Director and eight years as the General Manager of Riverside Public Utilities. Mr. Wright holds a bachelor’s degree in business and a master’s degree in business administration from California State University at Fullerton. Mr. Wright has served as past President of SCPPA and past President of the CMUA.

DAVID H. WIGGS, Chief Administrative Officer. Mr. Wiggs assumed his current post on May 1, 2014. Mr. Wiggs previously served the Department as its Senior Assistant General Manager – Power System earlier in 2014 and as its General Manager from 2001 to 2004. From 1996 to joining the Department as General Manager, Mr. Wiggs served as President and Principal of DHW Consulting, Inc. of Newport Beach, California, providing consulting and advisory services to the electric utility industry, including Pasadena Water and Power, the California State Assembly, El Paso Electric Company and the Department. From 1988 to 1996, Mr. Wiggs was with the El Paso Electric Company in El Paso, Texas, serving as Chairman, Chief Executive Officer and President. Prior to joining El Paso Electric Company, Mr. Wiggs was a public utility regulatory/finance attorney for 16 years. Mr. Wiggs holds a bachelor of business administration from Texas Tech University and a juris doctor degree from the University of Texas at Austin.

PHILIP R. LEIBER, Chief Financial Officer. Mr. Leiber assumed his current position on February 1, 2012. Prior to joining the Department, Mr. Leiber served as the Chief Financial Officer for Seattle City Light, a role he held from 2009 through 2012. Previously, Mr. Leiber was the Chief Financial Officer and Treasurer for the California Independent System Operator Corporation (“Cal ISO”), where he was employed from 1997 to 2009. Mr. Leiber also served as a manager with Coopers & Lybrand (now PricewaterhouseCoopers) in the Financial Advisory Services area. Mr. Leiber is a certified public accountant in California and a certified treasury professional. Mr. Leiber holds a bachelor’s degree in business administration and a master’s degree in accounting from the University of Michigan, and holds a master’s degree in Computer Information Systems from the University of Phoenix.

ANN M. SANTILLI, Assistant Chief Financial Officer and Controller. Ms. Santilli currently serves as Assistant Chief Financial Officer and Controller of the Department. Prior to holding this position, Ms. Santilli served as Interim Chief Financial Officer from October 2010 through January 2012. Prior to serving as Interim Chief Financial Officer, Ms. Santilli served as Chief Accounting Employee and Assistant Chief Financial Officer and Controller of the Department. She assumed the post as Controller in March 2008, as Assistant Chief Financial Officer in April 2008 and as Chief Accounting Employee in July 2010. Prior to being appointed as the Controller, Ms. Santilli was the Manager of Financial Reporting since 2003. Ms. Santilli has over 26 years of accounting and auditing experience. Ms. Santilli holds a bachelor’s degree in business administration from California State University at Northridge and is a certified public accountant in the State and a certified internal auditor.

MARIO C. IGNACIO, CFA, Chief Accounting Employee and Assistant Auditor. Mr. Ignacio serves as the Chief Accounting Employee and Assistant Auditor, as well as the Assistant Chief Financial Officer and Treasurer for the Department. Prior to his appointment as Chief Accounting Employee on October 5, 2010, Mr. Ignacio served as the Interim Chief Financial Officer of the Department. Mr. Ignacio has over 24 years of financial management experience emphasizing taxable fixed income investment and debt administration. His responsibilities include directing and managing trust fund portfolios with assets over $1 billion, administering and implementing debt-restructuring activities for the Department and certain Southern California Public Power Authority (“SCPPA”) projects, overseeing risk management and control, and monitoring credit for the utility’s wholesale marketing activities and natural
gas hedging program. Mr. Ignacio holds a bachelor’s degree “with distinction” in business administration and accountancy. He holds a master’s degree in business administration from the University of Southern California, where he was elected to the Beta Gamma Sigma Honor Society. He has earned the right to use the Chartered Financial Analyst (CFA) designation, is a member of the Los Angeles Society of Financial Analysts and the CFA Institute, and was the past president of the Los Angeles Civic Center Chapter of the Association of Government Accountants.

Employees

As of January 31, 2015, the Department assigned approximately 3,870 Department employees to the Power System on a full time basis. Approximately 3,507 additional Department employees support both the Power System and the Water System on a shared basis.

The Department conducts personnel functions in accordance with the Charter-established civil service system (the “Civil Service System”) applicable to most Department employees. In accordance with the Civil Service System, the Department makes appointments on the basis of merit through competitive examinations and civil service procedures. The position of General Manager and 14 other management positions are specifically exempted from the Civil Service System.

The City Council approves the wages and salaries paid to all Department employees. In accordance with State law (the Meyers-Milias-Brown Act) and a conforming City ordinance (the Employee Relations Ordinance), the Department recognizes fourteen bargaining units of Department employees. Five labor or professional organizations represent these employees’ bargaining units. In the bargaining process the Department and the labor or professional organizations develop memoranda of understanding which set forth wages, hours, overtime and other terms and conditions of employment.

The Department entered into ten memoranda of understanding with the International Brotherhood of Electrical Workers (“IBEW”) for a period extending through September 30, 2017. IBEW represents more than 90% of the Department’s employees through ten bargaining units. The agreement, which was approved by the City Council on December 10, 2013, provided for among other things, an increase to the retirement age for future Power System employees and a deferral of pay increases for three years. Changes to the Department pension program included the establishment of a second pension tier for new employees (see “Retirement and Other Benefits” below), as well as ending pension system reciprocity with the Los Angeles City Employees Retirement System (LACERS) for employees who transfer between the systems. The Coalition of L.A. City Unions, whose members are not employed at the Department, have challenged the ending of the reciprocity agreement. The Department and City intend to defend the challenge against the decision to end the reciprocity agreement.

The Department’s memorandum of understanding with the Service Employees International Union, Security Unit, expires on September 30, 2017, and its memoranda of understanding with the Load Dispatchers Association, Management Employees Association and the Association of Confidential Employees each expire on December 31, 2016. Since the advent of collective bargaining in 1974, work stoppages have been rare, occurring in 1974, 1981 and 1993.

Retirement and Other Benefits

Retirement, Disability and Death Benefit Insurance Plan.

The Department has a funded contributory retirement, disability, and death benefit insurance plan covering substantially all of its employees. The Water and Power Employees’ Retirement, Disability, and Death Benefit Insurance Plan (the “Plan”) operates as a single-employer defined benefit plan to provide pension benefits to eligible Department employees and to provide disability and death benefits from the respective insurance funds. Plan benefits are generally based on years of service, age at retirement, and the employee’s highest 12 consecutive months of salary before retirement. Active participants who joined the Plan on or after June 1, 1984 are required to contribute 6.00% of their annual covered payroll.
Participants who joined the Plan prior to June 1, 1984 contribute an amount based upon an entry-age percentage rate.

A new Tier 2 was added to the Plan and applies to members hired on or after January 1, 2014. Tier 2 plan participants are required to contribute 10% of their salary and plan benefits are based on a three-year final average salary period. The Plan’s actuary estimates the amount of contribution required to fund the benefit allocated to the current year of service (the “Normal Cost”), as a percentage of payroll, will be 5.61% for Tier 2 (as compared to 16.35% for Tier 1), and the new tier of benefits is projected to generate a present value savings of $877 million over the next 30 years (based on the 7.75% assumed rate of investment return on the Plan’s assets, which was in effect when Tier 2 was approved).

The Department contributes $1.10 for each $1.00 contributed by participants plus an actuarially determined annual required contribution (“ARC”) as determined by the Plan’s independent actuary, taking into consideration the amount of net pension asset or obligation currently recorded in the statement of net position. The required contributions are allocated between the Power System and the Water System based on the current year labor costs.

The Retirement Board of Administration (the “Retirement Board”) is the administrator of the Plan. The Plan is subject to provisions of the Charter and the regulations and instructions of the Board. The Plan is an independent pension trust fund of the City.

Plan amendments must be approved by both the Retirement Board and the Board. The Plan issues separately available financial statements on an annual basis. Such financial statements can be obtained from the Department of Water and Power Retirement Office, 111 N. Hope, Room 357, Los Angeles, California 90012.
The annual pension cost ("APC") and net pension asset for the Department’s Plan consist of the following (amounts in thousands):

<table>
<thead>
<tr>
<th></th>
<th>2014</th>
<th>2013</th>
</tr>
</thead>
<tbody>
<tr>
<td>Annual required contribution</td>
<td>$425,785</td>
<td>$408,475</td>
</tr>
<tr>
<td>Interest on net pension asset</td>
<td>(6,401)</td>
<td>(7,278)</td>
</tr>
<tr>
<td>Adjustment to annual required contribution</td>
<td>9,698</td>
<td>11,028</td>
</tr>
<tr>
<td>APC (including $161.1 million and $156.7 million of amounts capitalized in fiscal years 2014 and 2013, respectively)</td>
<td>429,082</td>
<td>412,225</td>
</tr>
<tr>
<td>Department contributions</td>
<td>(384,641)</td>
<td>(368,174)</td>
</tr>
<tr>
<td>Change in net pension asset</td>
<td>44,441</td>
<td>44,051</td>
</tr>
<tr>
<td>Net pension (asset) at beginning of year</td>
<td>34,127</td>
<td>(9,924)</td>
</tr>
<tr>
<td>Net pension liability (asset) at end of year</td>
<td>$78,568</td>
<td>34,127</td>
</tr>
</tbody>
</table>

Source: Department of Water and Power of the City of Los Angeles.

The Power System’s allocated share of the Plan’s APC and net pension asset consists of the following (amounts in thousands):

<table>
<thead>
<tr>
<th></th>
<th>2014</th>
<th>2013</th>
</tr>
</thead>
<tbody>
<tr>
<td>Annual required contribution</td>
<td>$289,534</td>
<td>$277,763</td>
</tr>
<tr>
<td>Interest on net pension asset</td>
<td>(4,352)</td>
<td>(4,949)</td>
</tr>
<tr>
<td>Adjustment to annual required contribution</td>
<td>6,594</td>
<td>7,499</td>
</tr>
<tr>
<td>APC (including $100.1 million and $97.9 million of amounts capitalized in fiscal years 2014 and 2013, respectively)</td>
<td>291,776</td>
<td>280,313</td>
</tr>
<tr>
<td>Power System contributions</td>
<td>(257,015)</td>
<td>(247,749)</td>
</tr>
<tr>
<td>Change in net pension asset</td>
<td>34,761</td>
<td>32,564</td>
</tr>
<tr>
<td>Net pension liability (asset) at beginning of year</td>
<td>50,773</td>
<td>18,209</td>
</tr>
<tr>
<td>Net pension liability at end of year</td>
<td>$85,534</td>
<td>50,773</td>
</tr>
</tbody>
</table>

Source: Department of Water and Power of the City of Los Angeles.

ARCs are determined through actuarial valuations using the entry-age normal actuarial cost method. The actuarial value of assets in excess of the Department’s Actuarial Accrued Liability ("AAL") is being amortized by level contribution offsets over rolling 15-year periods effective July 1, 2000.

In accordance with actuarial valuations, the Department’s required contribution rates are as follows:

<table>
<thead>
<tr>
<th>Fiscal Year</th>
<th>Normal cost</th>
<th>Deficit amortization</th>
<th>Contribution rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>2014</td>
<td>15.10%</td>
<td>30.44%</td>
<td>47.30%</td>
</tr>
<tr>
<td>2013</td>
<td>15.06%</td>
<td>29.30%</td>
<td>46.08%</td>
</tr>
</tbody>
</table>

Source: Department of Water and Power of the City of Los Angeles.
The significant actuarial assumptions include an investment rate of return of 7.75%, projected inflation adjusted salary increases of 3.50%, and cost-of-living increases of 3.00%. The actuarial value of assets is determined using techniques that smoothen the effects of short-term volatility in the market value of investments over a five-year period. Plan assets consist primarily of corporate and government bonds, common stocks, mortgage-backed securities, and short-term investments.

Trend information for fiscal years 2014, 2013, and 2012 for the Power System is as follows (amounts in thousands):

<table>
<thead>
<tr>
<th>Year ended June 30</th>
<th>Net pension liability (asset)</th>
<th>Percentage of APC contributed</th>
<th>APC</th>
</tr>
</thead>
<tbody>
<tr>
<td>2014</td>
<td>$ 85,534</td>
<td>88%</td>
<td>$ 291,776</td>
</tr>
<tr>
<td>2013</td>
<td>50,773</td>
<td>88</td>
<td>280,313</td>
</tr>
<tr>
<td>2012</td>
<td>18,209</td>
<td>87</td>
<td>250,497</td>
</tr>
</tbody>
</table>

Source: Department of Water and Power of the City of Los Angeles.

Disability and Death Benefits. The Power System’s allocated share of disability and death benefit plan costs and administrative expenses totaled $19.4 million and $19.4 million for fiscal years 2014 and 2013, respectively.

Funded Status and Funding Progress Based on Latest Actuarial Study.

On September 16, 2014, the latest actuarial study as of July 1, 2014 was completed for the Department for fiscal 2014. As of July 1, 2014, the Department’s actuarial value of assets was $8.9 billion and AAL for benefits was $11.0 billion resulting in an Unfunded Actuarial Accrued Liability (“UAAL”) of $2.1 billion. The covered payroll (annual payroll of active employees covered by the Plan) was $900 million, and the ratio of the UAAL to the covered payroll was 233%.

As of July 1, 2013, the Department’s actuarial value of assets was $7.96 billion and AAL for benefits was $10.10 billion, resulting in an UAAL of $2.14 billion. The covered payroll (annual payroll of active employees covered by the Plan) was $900 million, and the ratio of the UAAL to the covered payroll was 237%.

As of July 1, 2012, the Department’s actuarial value of assets was $7.57 billion and AAL for benefits was $9.69 billion, resulting in an UAAL of $2.12 billion. The covered payroll (annual payroll of active employees covered by the Plan) was $887 million, and the ratio of the UAAL to the covered payroll was 239%.

Actuarial valuations of an ongoing plan involve estimates of the value of reported amounts and assumptions about the probability of occurrence of events far into the future. Examples include assumptions about future employment, mortality, and the salary increases. Amounts determined regarding the funded status of the Plan and the ARCs of the Department are subject to continual revision as actual results are compared with past expectations and new estimates are made for the future. The schedule of funding progress, presented as required supplementary information, presents information about whether the actuarial value of plan assets is increasing or decreasing over time relative to the AAL for benefits.
Pension Plan – Schedule of Funding Progress. The following schedule provides information about the Department’s overall progress made in accumulating sufficient assets to pay benefits when due, prior to allocations to the Water System and the Power System (amounts in thousands):

<table>
<thead>
<tr>
<th>Actuarial valuation date July 1</th>
<th>Actuarial value of assets</th>
<th>Actuarial accrued liability (AAL)</th>
<th>Unfunded AAL (UAAL)</th>
<th>Funded ratio</th>
<th>Covered payroll</th>
<th>UAAL as a percentage of covered payroll</th>
</tr>
</thead>
<tbody>
<tr>
<td>2014</td>
<td>$8,877,595</td>
<td>$10,975,551</td>
<td>$2,097,956</td>
<td>81%</td>
<td>$900,126</td>
<td>233%</td>
</tr>
<tr>
<td>2013</td>
<td>7,958,488</td>
<td>10,094,868</td>
<td>2,136,380</td>
<td>79</td>
<td>900,254</td>
<td>237</td>
</tr>
<tr>
<td>2012</td>
<td>7,573,886</td>
<td>9,692,603</td>
<td>2,118,717</td>
<td>78</td>
<td>886,539</td>
<td>239</td>
</tr>
</tbody>
</table>

Source: Department of Water and Power of the City of Los Angeles.

As of July 1, 2014, the Plan had unrecognized investment gains of approximately $735 million. The Plan employs a 5-year smoothing technique to value assets in order to reduce the volatility in contribution rates. The impact of this will result in “smoothed” assets that are lower or higher than the market value of the assets depending upon whether the remaining amount to be smoothed is a net gain or a net loss. If the unrecognized investments gains for the year ended June 30, 2014 were recognized immediately, required contributions to the Plan would decrease from approximately 50.62% of total Department covered payroll to 41.69% of total Department covered payroll. Additionally, if the unrecognized investments gains in all available Plan funds were recognized immediately in the actuarial value of assets, the funded ratio of the Plan would increase from approximately 80.9% to 88.5%.

The Department will be adopting the provisions of GASB Statement No. 68, Accounting and Financial Reporting for Pension Plans – an amendment of GASB Statement No. 27 (“GASB No. 68”) before the end of Fiscal Year 2014-15. GASB No. 68 requires employers to include the unfunded pension liability on their financial statements and establishes standards for the determination of pension expense. The Department is in the process of working with its actuary on the appropriate actuarial assumptions that need to be established so pension expense and other financial events may be calculated in accordance with GASB No. 68. The Power System is currently evaluating the impact of GASB No. 68 on its financial statements.

Other Postemployment Benefit (Healthcare) Plan.

Plan Description. The Department provides certain other postemployment benefits (“OPEB”), such as medical and dental plans, to active and retired employees and their dependents. The healthcare plan is administered by the Department. The Retirement Board and the Board have the authority to approve provisions and obligations. Eligibility for benefits for retired employees is dependent on a combination of age and service of the participants pursuant to a predetermined formula. Any changes to these provisions must be approved by the Retirement Board and the Board. The total number of active and retired Department participants entitled to receive benefits was approximately 16,491 and 16,319 for the fiscal years ended June 30, 2014 and 2013, respectively.

The health plan is a single-employer defined benefit plan. During fiscal year 2007, the Retiree Health Benefits Fund (the “Fund”) was created to fund the postemployment benefits of the Department. The Fund is administered as a trust and has its own financial statements. Such financial statements can be obtained from the Department of Water and Power Retirement Office, 111 N. Hope, Room 357, Los Angeles, California 90012.

Funding Policy. The Department pays a monthly maximum subsidy of $1,704 for medical and dental premiums depending on the employee’s work location and benefits earned. Participants choosing plans with a cost in excess of the subsidy they are entitled to are required to pay the difference.
Although no formal funding policy has been established for the future benefits to be provided under this plan, the Department has made significant contributions into the Fund during previous years. In fiscal year 2014, the Department paid $74.6 million in retiree medical premiums. In fiscal year 2013, the Department paid $69.1 million in retiree medical premiums. No additional transfers to the Fund were made in fiscal years 2014 and 2013. The Power System’s portion of retiree medical premium payments was $50.7 million and $47.0 million for 2014 and 2013, respectively.

**Annual OPEB Cost and Net OPEB Obligation.** The annual OPEB cost (expense) is calculated based on the employer ARC, an amount actuarially determined in accordance with the parameters of GASB Statement No. 45 *Accounting and Financial Reporting by Employers for Postemployment Benefits Other Than Pensions*. The ARC represents a level of funding that, if paid on an ongoing basis, is projected to cover normal cost under each year and amortize any unfunded actuarial liabilities (or funding excess) over a period not to exceed 30 years.

The following table shows the components of the Department’s annual OPEB cost for the year, the amount actually contributed to the Plan, and changes in the net OPEB asset (amounts in thousands):

<table>
<thead>
<tr>
<th></th>
<th>Year ended June 30</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2014</td>
</tr>
<tr>
<td>Annual required contribution</td>
<td>$ 60,676</td>
</tr>
<tr>
<td>Interest on net OPEB asset</td>
<td>(76,461)</td>
</tr>
<tr>
<td>Adjustment to annual required contribution</td>
<td>66,869</td>
</tr>
<tr>
<td>Annual OPEB costs</td>
<td>51,084</td>
</tr>
<tr>
<td>Department contributions made</td>
<td>(74,625)</td>
</tr>
<tr>
<td>Change in net OPEB asset</td>
<td>(23,541)</td>
</tr>
<tr>
<td>Net OPEB asset – beginning of year</td>
<td>(954,690)</td>
</tr>
<tr>
<td>Net OPEB asset – end of year</td>
<td>$ (978,231)</td>
</tr>
</tbody>
</table>

Source: Department of Water and Power of the City of Los Angeles.

The following table shows the components of the Power System’s share in annual OPEB cost for the year, the amount actually contributed to the plan, and changes in the net OPEB asset (amounts in thousands):

<table>
<thead>
<tr>
<th></th>
<th>Year ended June 30</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2014</td>
</tr>
<tr>
<td>Annual required contribution</td>
<td>$ 41,259</td>
</tr>
<tr>
<td>Interest on net OPEB asset</td>
<td>(51,993)</td>
</tr>
<tr>
<td>Adjustment to annual required contribution</td>
<td>45,471</td>
</tr>
<tr>
<td>Annual OPEB costs</td>
<td>34,737</td>
</tr>
<tr>
<td>Power System contributions made</td>
<td>(50,749)</td>
</tr>
<tr>
<td>Change in net OPEB asset</td>
<td>(16,012)</td>
</tr>
<tr>
<td>Net OPEB asset – beginning of year</td>
<td>(652,439)</td>
</tr>
<tr>
<td>Net OPEB asset – end of year</td>
<td>$ (668,451)</td>
</tr>
</tbody>
</table>

Source: Department of Water and Power of the City of Los Angeles.
The Department’s annual OPEB cost, the percentage of ARC contributed to the Plan, and the net postemployment asset for fiscal years 2014, 2013 and 2012 were as follows (amounts in thousands):

<table>
<thead>
<tr>
<th></th>
<th>2014</th>
<th>2013</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td>Annual OPEB cost</td>
<td>$51,084</td>
<td>$38,311</td>
<td>$41,620</td>
</tr>
<tr>
<td>Percentage of OPEB costs contributed</td>
<td>146%</td>
<td>180%</td>
<td>244%</td>
</tr>
<tr>
<td>Net postemployment asset at end of year</td>
<td>$978,231</td>
<td>$954,690</td>
<td>$923,874</td>
</tr>
</tbody>
</table>

Source: Department of Water and Power of the City of Los Angeles.

The Power System’s share in the annual OPEB cost, the percentage of ARC contributed to the Plan, and the net retirement asset for fiscal years 2014, 2013 and 2012 were as follows (amounts in thousands):

<table>
<thead>
<tr>
<th></th>
<th>2014</th>
<th>2013</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td>Annual OPEB cost</td>
<td>$34,737</td>
<td>$26,051</td>
<td>$28,301</td>
</tr>
<tr>
<td>Percentage of OPEB costs contributed</td>
<td>146%</td>
<td>180%</td>
<td>144%</td>
</tr>
<tr>
<td>Net postemployment asset at end of year</td>
<td>$668,451</td>
<td>$652,439</td>
<td>$631,479</td>
</tr>
</tbody>
</table>

Source: Department of Water and Power of the City of Los Angeles.

**Funded Status and Funding Progress Based on Latest Actuarial Study.** On October 14, 2014, the latest actuarial study as of July 1, 2014 was completed for fiscal 2015. As of July 1, 2014, the Department’s actuarial value of assets was $1.49 billion and AAL for benefits was $1.95 billion, resulting in a UAAL of $0.46 billion. The covered payroll (annual payroll of active employees covered by the Plan) was $900 million, and the ratio of the UAAL to the covered payroll was 51%.

As of July 1, 2013, the Department’s actuarial value of assets was $1.33 billion and AAL for benefits was $1.74 billion, resulting in a UAAL of $0.41 billion. The covered payroll (annual payroll of active employees covered by the Plan) was $900 million, and the ratio of the UAAL to the covered payroll was 46%.

As of July 1, 2012, the Department’s actuarial value of assets was $1.25 billion and AAL for benefits was $1.57 billion, resulting in a UAAL of $0.32 billion. The covered payroll (annual payroll of active employees covered by the Plan) was $887 million, and the ratio of the UAAL to the covered payroll was 36%.

Actuarial valuations of an ongoing plan involve estimates of the value of reported amounts and assumptions about the probability of occurrence of events far into the future. Examples include assumptions about future employment, mortality, and the healthcare cost trend. Amounts determined regarding the funded status of the Plan and the ARCs of the Department are subject to continual revision as actual results are compared with past expectations and new estimates are made for the future. The schedule of funding progress presents information about whether the actuarial value of plan assets is increasing or decreasing over time relative to the AAL for benefits.

**Actuarial Methods and Assumptions.** Projections of benefits for financial reporting purposes are based on the substantive plan (the plan understood by the Department and the plan members) and include the types of benefits provided at the time of each valuation and the historical pattern of sharing of benefit costs between the Department and the plan members to that point. The actuarial methods and assumptions used include techniques that are designed to reduce the effects of short-term volatility in AAL and the actuarial value of assets, consistent with the long-term perspective of the calculations.
In the July 1, 2013 actuarial valuation, the entry-age normal cost method was used. The actuarial assumptions include 7.75% discount rate, which represents the expected long-term return on plan assets, and an annual healthcare cost trend rate of 8.00% initially, reduced by decrements to an ultimate rate of 5.00% over 7 years. Both rates include a 3.50% inflation assumption. The actuarial value of assets was determined using techniques that spread UAAL being amortized as a level percentage of projected payroll over a closed 30-year period with 22 years remaining.

In the July 1, 2012 actuarial valuation, the entry-age normal cost method was used. The actuarial assumptions include 7.75% discount rate, which represents the expected long-term return on plan assets, an annual healthcare cost trend rate of 8.50% initially, reduced by decrements to an ultimate rate of 5.00% over 7 years. Both rates include a 3.50% inflation assumption. The actuarial value of assets was determined using techniques that spread UAAL being amortized as a level percentage of projected payroll over a closed 30-year period with 23 years remaining.

In the July 1, 2011 actuarial valuation, the entry-age normal cost method was used. The actuarial assumptions include 7.75% discount rate, which represents the expected long-term return on plan assets, an annual healthcare cost trend rate of 9.00% initially, reduced by decrements to an ultimate rate of 5.00% over 10 years. Both rates include a 3.50% inflation assumption. The actuarial value of assets was determined using techniques that spread UAAL being amortized as a level percentage of projected payroll over a closed 30-year period with 24 years remaining.

Healthcare Reform Legislation. The Patient Protection and Affordable Care Act (“PPACA”) was signed into law on March 23, 2010. One key provision of the PPACA is the assessment of the excise tax on high cost plans (Cadillac Plans) beginning in 2018. Under the PPACA, a 40% excise tax applies to plans with costs exceeding certain annual thresholds for non-Medicare retirees aged 55-64 ($11,850 for single coverage; $30,950 for families coverage). For all other retirees the thresholds in 2018 are $10,200 for single coverage and $27,500 for family coverage. Significant uncertainties exist regarding the impact of the excise tax on high cost plans without further regulatory guidance. Management estimated the potential impact of this tax on the liability is based on unadjusted thresholds and assuming the tax is shared between the Department and its participants in the same way that the current costs are shared. The estimated impact of the 40% excise tax provision on high cost plans beginning in 2018, under the healthcare reform, is reflected in all actuarial valuation reports after July 1, 2010.

Postemployment Healthcare Plan – Schedule of Funding Progress. The following schedule provides information about the Department’s overall progress made in accumulating sufficient assets to pay benefits when due, prior to allocations to the Water System and the Power System (amounts in thousands):

<table>
<thead>
<tr>
<th>Actuarial valuation date July 1</th>
<th>Actuarial value of assets</th>
<th>Actuarial accrued liability (AAL)</th>
<th>Unfunded AAL (UAAL)</th>
<th>Funded ratio</th>
<th>Covered payroll</th>
<th>UAAL as a percentage of covered payroll</th>
</tr>
</thead>
<tbody>
<tr>
<td>2014</td>
<td>$1,485,140</td>
<td>$1,947,912</td>
<td>$462,772</td>
<td>76%</td>
<td>$900,126</td>
<td>51%</td>
</tr>
<tr>
<td>2013</td>
<td>1,332,136</td>
<td>1,743,727</td>
<td>411,591</td>
<td>76</td>
<td>900,254</td>
<td>46</td>
</tr>
<tr>
<td>2012</td>
<td>1,244,039</td>
<td>1,566,059</td>
<td>322,020</td>
<td>79</td>
<td>886,539</td>
<td>36</td>
</tr>
</tbody>
</table>

As of June 30, 2014, the Healthcare Benefits had unrecognized investment gain of approximately $126.7 million. The actuarial valuations of the Healthcare Benefits employ a smoothing policy which requires that market gains and losses be recognized in even increments over five years. As a result, the impact of this will result in “smoothed” assets that are lower or higher than the market value of the assets depending upon whether the remaining amount to be smoothed is either a net gain or a net loss. Recent market gains will be amortized and evidenced in actuarial valuations and funded status over the next five years.
Effective January 1, 2014, the Board approved a new tier for new Plan members called “Tier 2.” Tier 2 provides reduced retiree healthcare benefits. The Plan’s actuary estimates the Normal Cost, as a percentage of payroll, will be 2.63% for Tier 2 (as compared to 4.33% for Tier 1), and the new tier of benefits is projected to generate a present value savings of $136.5 million over the next 30 years.

Transfers to the City

Pursuant to the Charter, the City Council may, subject to the provisions of contractual obligations, direct a transfer of surplus money in the Power Revenue Fund to the City’s reserve fund (a “Power Transfer”) with the consent of the Board. The Board may withhold its consent if it finds that making the Power Transfer would have a material adverse impact on the Department’s financial condition in the year the Power Transfer is to be made. In the event the Board does not approve any year’s Power Transfer, the City Administrative Officer is to verify the Department’s findings and make a report thereon and recommendations with respect thereto. After receiving such report, and in consultation with the City Council and the Mayor, the Board shall either amend or uphold its preliminary findings.

Pursuant to covenants contained in Resolution No. 4596 adopted by the Board on February 6, 2001 (the “Master Resolution”), a Power Transfer may not exceed the net income of the prior Fiscal Year or reduce the Power System’s surplus to less than 33-1/3% of total Power System indebtedness. Subject to the restrictions of the Charter and the Master Resolution, the Department’s current practice is to consent to a Power Transfer in each of its Fiscal Years (currently July 1 of a year to June 30 of the following year) equal to approximately 8% of the Power System’s operating revenues for the preceding Fiscal Year. The Board has approved transfers totaling $265,586,000 to the City during the Fiscal Year ending June 30, 2015.

The following table shows the amounts of the Power Transfer in each of the last five Fiscal Years:

<table>
<thead>
<tr>
<th>Fiscal Year Ended June 30</th>
<th>Amount of Power Transfer</th>
</tr>
</thead>
<tbody>
<tr>
<td>2011</td>
<td>$258,815</td>
</tr>
<tr>
<td>2012</td>
<td>250,077</td>
</tr>
<tr>
<td>2013</td>
<td>246,534</td>
</tr>
<tr>
<td>2014</td>
<td>253,000</td>
</tr>
<tr>
<td>2015</td>
<td>265,586*</td>
</tr>
</tbody>
</table>

Source: Department of Water and Power of the City of Los Angeles.

* This amount is expected to be transferred to the City in installments: an initial payment of $132,793,000 expected to be made in March 2015 followed by equal remaining monthly payments thereafter, so that by June 30, 2015, the full amount has been paid.

In February 2015, litigation was served upon the Department (Chapman v. The City of Los Angeles et al., Los Angeles Superior Court Case No. BS 153395) seeking an injunction to prevent the Power Transfer. In the event of an adverse judgment in this litigation, the Department may be precluded from making future Power Transfers to the extent such transfer exceeds the reasonable costs of services provided by the City. The Department sets its rates and its budget with the expectation that the Power Transfer is made. Therefore, any adverse judgment in this litigation would not have a material adverse effect on the financial position of the Department.
Insurance

The Department’s insurance program currently consists of a combination of commercial insurance policies and self-insurance. The Department carries commercial excess general liability insurance in the amount of $115 million, with a $3 million self-insured retention. General liability claims under $3 million are covered under the Department’s self-insurance program. As of January 31, 2015, the portion of the Power Revenue Fund set aside for self-insurance had a balance of approximately $142,475,000. The Department annually reviews the amount retained for self-insurance and may adjust such amount if it deems such adjustment appropriate. Limits maintained by the Department are subject to change depending on insurance market conditions and assessments by the Department as to risk exposure.

The Department commercially insures its physical plant through a policy of all risk property insurance, which is written on a replacement cost-basis. The policy covers all risk of physical loss or damage to buildings, structures, auxiliary and main plant equipment. Such insurance has a policy limit of $500 million per occurrence with an aggregate limit for all claims in a single year of $500 million. The all risk property insurance has a multi-tiered deductible structure, with deductibles ranging from $500,000 to $10 million depending on location. The Department does not insure its physical plants located in the State of California (the “State”) against the risk of physical loss or damage due to earthquakes; however assets outside the State are insured against damage from earthquakes. The Department has obtained a waiver from the State Insurance Commissioner’s Office requiring Federal Emergency Management Agency (“FEMA”) insurance that enables the Department to be eligible for reimbursement from FEMA in the event of earthquake loss or damage in the State.

As a participant in the Navajo Generating Station (the “Navajo Station”), Palo Verde Nuclear Generating Station (“PVNGS”) and associated transmission systems, the Department is a named additional insured on various forms of insurance providing protection against property and liability losses relating to such facilities. The amounts of coverage are established by participating owners and procured by the operating agent for each facility.

The Department, as the operating agent for the Intermountain Power Project (“IPP”), the Mead-Adelanto Transmission Project (the “Mead-Adelanto Project”), the Pacific DC Intertie and other entities or agencies, includes such entities or agencies as named additional insureds on the various forms of insurance procured for such facilities.

The Department continuously evaluates its insurance program and may modify the current configuration of commercial insurance and self-insurance with respect to the Power System.

Investment Policy and Controls

Department’s Trust Funds Investment Policy. The majority of the Power System funds are held in the Power Revenue Fund, investments of which are managed by the Treasurer of the City. The funds have been invested as part of the City’s investment pool program since 1983. Certain financial assets of the Department that are held in special-purpose trust or escrow funds more fully described in “Note (7) – Cash, Cash Equivalents, and Investments” in Appendix A (“Trust Funds”) with an independent trustee are not included in the City’s investment pool program. The Department manages the investment of the Trust Funds in which approximately $631.1 million (investments at fair market value) was on deposit as of January 31, 2015. The Department’s investment of such funds complies with the California Government Code in all material respects and such funds are invested according to the Department’s Trust Funds Investment Policy (the “Trust Funds Investment Policy”), which sets forth investment objectives and constraints. For more information about the Trust Funds Investment Policy, see “Note (7) – Cash, Cash Equivalents, and Investments” in Appendix A. Such funds consist of debt reduction trust funds, the nuclear decommissioning trust funds, the natural gas trust fund, and the hazardous waste treatment storage and disposal trust fund. These trust funds are being held by U.S. Bank National Association as trustee/custodian. Amounts in the debt reduction trust fund are to be applied to the retirement (including
the payment of debt service, purchase, redemption and defeasance) of Power System debt, including obligations to Intermountain Power Agency (“IPA”) and SCPPA. As of January 31, 2015, the debt reduction trust fund had a balance of approximately $499.2 million (investments at fair market value).

Under the Trust Funds Investment Policy, the Department’s investment program seeks to accomplish three specific goals: (i) preserve the principal value of the funds, (ii) ensure that investments are consistent with each individual fund’s liquidity needs and (iii) achieve the maximum yield/return on the investments.

The overall responsibility for managing the Department’s investment program for the Trust Funds rests with the Department’s Chief Financial Officer, who directs investment activities through the Department’s Assistant Chief Financial Officer and Treasurer. An Investment Committee, comprised of the City Controller, a Board member designated by the Board President, the General Manager and the Department’s Chief Financial Officer (the “Department Investment Committee”) is charged with oversight responsibility. The Trust Funds Investment Policy is adopted by the Board from time to time, and fund activity is reviewed periodically by the Department Investment Committee to ensure its consistency with the overall objectives of the policy, as well as its relevance to current law and financial and economic trends.

The Department’s Assistant Chief Financial Officer and Treasurer or his designee reviews all investment transactions for the Trust Funds on a monthly basis for control and compliance and submits quarterly investment reports that summarize investment income to the Department Investment Committee, the Board and the Mayor for information and evaluation.

### POWER SYSTEM TRUST FUND INVESTMENTS

**ASSETS AS OF JANUARY 31, 2015**

**(Dollars in Thousands)**

<table>
<thead>
<tr>
<th>Fair Market Value</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>U. S. Government Securities</td>
<td>5,007</td>
</tr>
<tr>
<td>U. S. Sponsored Agency Issues</td>
<td>310,907</td>
</tr>
<tr>
<td>Medium term notes</td>
<td>120,299</td>
</tr>
<tr>
<td>Municipal obligations</td>
<td>23,569</td>
</tr>
<tr>
<td>California state bonds</td>
<td>23,391</td>
</tr>
<tr>
<td>Other state bonds</td>
<td>56,493</td>
</tr>
<tr>
<td>Commercial paper</td>
<td>44,745</td>
</tr>
<tr>
<td>Certificates of deposit</td>
<td>26,998</td>
</tr>
<tr>
<td>Bankers acceptances</td>
<td>535</td>
</tr>
<tr>
<td>Money market funds</td>
<td>19,195</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>631,139</strong></td>
</tr>
</tbody>
</table>

*Source: Department of Water and Power of the City of Los Angeles.*

*Totals may not equal sum of parts due to rounding.

*Department Financial Risk Management Policies*

In order to manage certain financial and operational risk, the Board has adopted a number of policies in addition to its Trust Funds Investment Policy. The Board has adopted a Counterparty Evaluation Credit Policy designed to minimize the Department’s credit risk with its counterparties. This policy applies to wholesale energy, transmission, physical natural gas and financial natural gas transactions entered into by the Department. Pursuant to this policy the Department assigns credit ratings to such counterparties. The policy requires the use of standardized netting agreements which require such counterparties to net positive and negative exposures to the Department and requires credit enhancement.
from counterparties that do not meet an acceptable level of risk. Sales to such counterparties are only permitted up to the amount of purchases with a netting agreement and, in certain cases, credit enhancement in place.

The Board has adopted a Retail Natural Gas Risk Management Policy designed to mitigate the Department’s exposure to unexpected spikes in the price of natural gas used in the production of electricity to serve retail customers, as authorized by the Charter and the Los Angeles Administrative Code. This policy authorizes Department management to enter into transactions for natural gas subject to specified parameters, such as duration of contract and price and volumetric limits. It also establishes internal controls for natural gas risk management activity. See “THE POWER SYSTEM – Fuel Supply for Department-Owned Generating Units and Apex Power Project.”

The Board has adopted a Wholesale Marketing Energy Risk Management Policy to establish a risk management program designed to manage the Department’s exposure to risks resulting from purchases and sales of wholesale energy, transmission services and ancillary services as authorized by the Charter and the Los Angeles Administrative Code. This policy establishes the General Manager’s authority to enter into such transactions, identifies approved transaction types and establishes internal controls for wholesale energy risk management activity.

City Investment Policy

The City Treasurer invests temporarily idle cash on behalf of the City, including that of the proprietary departments, such as the Department, as part of a pooled investment program. As of January 31, 2015, the Power System has approximately $975 million of unrestricted cash and approximately $941 million of restricted cash on deposit with the City. The City’s pooled investment program combines general receipts with special funds for investment purposes and allocates interest earnings and losses on a pro-rata basis when the interest is earned and distributes interest receipts based on the previously established allocations. The primary responsibilities of the City Treasurer and the pooled investment program are to protect the principal and asset holdings of the City’s portfolio and to ensure adequate liquidity to provide for the prompt and efficient handling of City disbursements.

CITY OF LOS ANGELES POOLED INVESTMENT FUND
ASSETS AS OF JUNE 30, 2014
(Dollars in Thousands)
(Unaudited)

<table>
<thead>
<tr>
<th>Amount</th>
<th>Percent of Total</th>
<th>Power System Share</th>
</tr>
</thead>
<tbody>
<tr>
<td>U.S. Sponsored Agency Issues</td>
<td>$1,915,548</td>
<td>22.05%</td>
</tr>
<tr>
<td>U.S. Treasury Notes</td>
<td>4,121,579</td>
<td>47.44</td>
</tr>
<tr>
<td>U.S. Treasury Bills</td>
<td>248,766</td>
<td>2.86</td>
</tr>
<tr>
<td>Medium term notes</td>
<td>1,443,640</td>
<td>16.62</td>
</tr>
<tr>
<td>Commercial paper</td>
<td>904,407</td>
<td>10.41</td>
</tr>
<tr>
<td>Securities Lending Cash Collateral</td>
<td>11,425</td>
<td>0.13</td>
</tr>
<tr>
<td>Short-term investment funds</td>
<td>5,609</td>
<td>0.06</td>
</tr>
<tr>
<td>Municipal Bonds</td>
<td>30,207</td>
<td>0.35</td>
</tr>
<tr>
<td>Certificates of Deposit</td>
<td>7,000</td>
<td>0.08</td>
</tr>
<tr>
<td><strong>Total General and Special Pools</strong></td>
<td><strong>$8,688,181</strong></td>
<td><strong>100.00%</strong></td>
</tr>
</tbody>
</table>

Source: Department of Water and Power of the City of Los Angeles and Los Angeles City Treasurer.
Note: Department funds held by the City are both unrestricted and restricted funds. Totals may not equal sum of parts due to rounding.
The City’s investment operations are managed in compliance with the California Government Code and the City’s statement of investment policy, which sets forth permitted investments, liquidity parameters and maximum maturity of investments. The investment policy is reviewed and approved by the City Council on an annual basis. An Investment Advisory Committee, comprised of the City Treasurer (who is also the General Manager of the City’s Office of Finance), City Controller, Chief Legislative Analyst, Chief Administrative Officer’s office and a contracted financial advisor, is charged with oversight responsibility to ensure conformity with the investment policy. The Association of Public Treasurers of the United States and Canada has certified the City’s investment policy through its Investment Policy Program.

Monthly reports of investment activity are presented to the Mayor, the City Council and the Department to indicate, among other things, compliance with the investment policy. The City’s Office of Finance does not invest in structured and range notes, securities that could result in zero interest accrual if held to maturity, variable rate, floating rate or inverse floating rate investments and mortgage-derived interest or principal-only strips.

The investment policy permits the City’s Office of Finance to engage custodial banks to enter into short-term arrangements to lend securities to various brokers. Cash and/or securities (United States Treasuries and Federal Agencies only) collateralize these lending arrangements, the total value of which is at least 102% of the market value of securities loaned out. The securities lending program is limited to a maximum of 20% of the market value of the City’s Office of Finance’s pool by the City’s investment policy and the California Government Code.

**ELECTRIC RATES**

**Rate Setting**

Pursuant to the Charter, the Board, subject to the approval of the City Council by ordinance (as discussed below), fixes the rates for electric service from the Power System (“Electric Rates”). The Charter provides that the Electric Rates shall be fixed by the Board from time to time as necessary. The Charter also provides that the Electric Rates shall, except as authorized by the Charter, be of uniform operation for customers of similar circumstances throughout the City, as near as may be, and shall be fair and reasonable, taking into consideration, among other things, the nature of the uses, the quantity supplied and the value of the service provided. The Charter further provides that rates for electric energy may be negotiated with individual customers, provided that such rates are established by binding contract, contribute to the financial stability of the Power System and are consistent with such procedures as the City Council may establish.

The Board is obligated under the Charter and the rate covenant in the Master Resolution to establish Electric Rates and collect charges in amounts which, together with other available funds, shall be sufficient to service the Department’s Power System indebtedness and to meet the Power System’s expenses of operation and maintenance. The Charter provides that Electric Rates are subject to the approval of the City Council by ordinance (a “Rate Ordinance”). The Charter further requires that the City Council approve Rate Ordinances for the Electric Rates prescribed in the rate covenant in the Charter, which rate covenant is also included in the Master Resolution.

The Department’s latest rate action resulted in planned annual system average Electric Rate increases of approximately 4.9% for Fiscal Year 2012-13 and 6.0% for Fiscal Year 2013-14, with actual rate adjustments that varied depending on actual costs reflected in the pass-through rates. The rate increase over these two Fiscal Years is reflected in the Incremental Electric Rate Ordinance and as a result, effective November 11, 2012, the Department’s electric retail revenue has been funded from the existing Rate Ordinance and the Incremental Electric Rate Ordinance through the following major components:
(a) Under the existing Rate Ordinance:

(i) Base Rates: Base Rates are used to fund expenditures including debt service arising from capital projects (except projects relating to the Renewable Portfolio Standard) (“RPS”), operational and maintenance expenses (except as RPS related), public benefit spending, property tax, and a prorated portion of the Power Transfer;

(ii) Reliability Cost Adjustment (the “RCA”): The RCA is used to recover certain power reliability expenditures; and

(iii) Energy Cost Adjustment (the “ECA”): The ECA is used to recover expenditures for fuel, non-renewable purchased power, RPS and energy efficiency-related expenditures.

(b) Under the Incremental Electric Rate Ordinance:

(i) Incremental Base Rates: The Incremental Base Rates are used to recover costs of providing electric utility service that are not recovered by Base Rates or any of the Rate Ordinance cost adjustments, including labor costs, real estate costs, costs to rebuild and operate local power plants, equipment costs, operation and maintenance costs, expenditures for jointly owned plants and other inflation-sensitive costs;

(ii) Incremental Reliability Cost Adjustment (the “IRCA”): The IRCA is used to recover costs associated with operations and maintenance, debt service expense of the Power System Reliability Program and RCA under-collection;

(iii) Variable Energy Adjustment (the “VEA”): The VEA is used to recover costs associated with fuel, non-renewable portfolio standard power purchase agreements, economy purchases, legacy ECA under-collection and Base Rates decoupling from energy efficiency impact;

(iv) Capped Renewable Portfolio Standard Energy Adjustment (the “CRPSEA”): The CRPSEA is used to recover costs associated with RPS operations and maintenance, debt service and energy efficiency programs; and

(v) Variable Renewable Portfolio Standard Energy Adjustment (the “VRPSEA”): The VRPSEA is used to recover costs associated with RPS market purchases and costs above any operations and maintenance and debt service payments.

The RCA, ECA, VEA, CRPSEA and VRPSEA are pass-through cost adjustments applied by factors that the Department may change with approval of the Board, without changes to existing Rate Ordinances. During Fiscal Year 2014-15, the normal adjustments of the pass-through cost adjustments are expected to continue. Retail rate changes involving changes to the Incremental Rate Ordinance are contemplated for Fiscal Year 2015-16, but at this time, the Department has not formally proposed such changes. The Department expects to announce rate plans for Fiscal Year 2015-16 during the summer of 2015. Changes to the Rate Ordinances require both Board and City Council approval.

Board Adopted Financial Planning Criteria. The Board has directed the Department to use the following criteria when preparing the Power System’s financial plans with respect to Electric Rates: (i) maintain a minimum debt service coverage at 2.25 times, (ii) maintain a minimum operating cash target of the equivalent of 170 days of operating expenses, (iii) maintain full obligation coverage of at
least 1.7 times, and (iv) maintain a debt-to-capitalization ratio of less than 68%. These criteria are subject to ongoing reviews and adjustments by the Board with advice from the Department’s financial advisors and were most recently revised on May 20, 2014.

**Neighborhood Councils.** Pursuant to a Memorandum of Understanding with the City’s Neighborhood Councils, the Department agreed to use its best efforts to undertake a 90-day or 120-day notification and outreach period (depending on the duration of the Department’s proposed rate action) prior to submitting a residential or non-residential retail business customer electric rate increase proposal involving changes to the Rate Ordinances to the Board for approval. The Neighborhood Councils have indicated they will use their best efforts to provide written input regarding such rate proposals to the Department within 60 days of receiving the above-discussed notifications.

**Office of Public Accountability.** Section 683 of the Charter establishes the Office of Public Accountability (the “OPA”) with respect to the Department. The primary role of the OPA is providing public, independent analysis to the Board and City Council about Department actions as they relate to water rates and the Electric Rates. The role of the OPA is advisory rather than an approver of Electric Rates. The OPA is headed by an Executive Director appointed by a citizens committee, subject to confirmation by the City Council and Mayor, who serves as the Ratepayer Advocate for the OPA. On February 1, 2012, Dr. Frederick H. Pickel was appointed as Executive Director of the OPA (the “Ratepayer Advocate”). The rate action effective November 11, 2012, was supported by the Ratepayer Advocate following his review of the proposed rate changes. The rate action included certain changes proposed by the Ratepayer Advocate. The Ratepayer Advocate also provided a list of additional recommendations for potential implementation by the Department prior to any further rate actions. The Department is working to address these matters and is required to provide progress reports to the City Council on the status of certain of the recommendations.

**Rate Regulation**

While changes in the retail Electric Rate ordinance are subject to approval by the City Council, the authority of the Board to impose and collect retail Electric Rates for service from the Power System is not subject to the general regulatory jurisdiction of the California Public Utilities Commission (the “CPUC”) or any other State or federal agency. The California Public Utilities Code (the “Public Utilities Code”) contains certain provisions affecting all municipal utilities such as the Power System. At this time, neither the CPUC nor any other regulatory authority of the State nor FERC approves the Department’s retail Electric Rates. It is possible that future legislative and/or regulatory changes could subject the Department to the jurisdiction of the CPUC or to other limitations or requirements.

Although its retail Electric Rates are not subject to approval by any federal agency, the Department is subject to certain provisions of the Public Utilities Code and the Public Utility Regulatory Policies Act of 1978 (“PURPA”). PURPA applies to the purchase of the output of “qualified facilities” (“QFs”) at prices determined in accordance with PURPA. The Energy Policy Act of 2005 repealed the mandatory purchase obligation for utilities (including the Department) when FERC determines that the QFs have access to a competitive sales market and open access transmission. The Department believes that it is currently operating in compliance with PURPA.

Under federal law, FERC has the authority, under certain circumstances and pursuant to certain procedures, to order any utility (municipal or otherwise), including the Department, to provide transmission access to others at cost-based rates. FERC also has licensing authority over various hydroelectric facilities owned and operated by the Department.

Furthermore, with, among other things, the consent of the Department, the transmission facilities owned or controlled by the Department may be included in the California statewide network administered by Cal ISO. See “THE POWER SYSTEM – Transmission and Distribution Facilities.” The California
Energy Resources Conservation and Development Commission, commonly referred to as the California Energy Commission (the “CEC”), is authorized to evaluate rate policies for electric energy as related to the goals of the Warren-Alquist State Energy Resources Conservation and Development Act (Public Resources Code Section 25000 et seq.) and make recommendations to the Governor of the State, the Legislature and publicly-owned electric utilities. The Department is in the process of updating the Open Access Transmission Tariff, which includes revising the cost-of-service and rate design for the Department’s wholesale transmission rates.

Billing and Collections

The Department currently bills residential customers on a bimonthly basis and commercial and industrial customers on a monthly basis. The Department prepares bills covering water and electric charges and non-Department charges (such as sewer services, a sanitation equipment charge and State and local taxes). In general, payments received by the Department are credited to the billed amounts in the following priority: water charges, electric charges, State and local taxes, sewer service charge and sanitation equipment charge. Payments received are credited first to amounts in arrears and then to the current amounts for each charge in the priority described above. From September 2013 through June 2014, this sequence was followed except that arrears date was not considered. In July 2014, arrears date was reinstated in the sequence as described above.

In September 2013, the Department implemented a new customer information system. The system is being used and the Department is making adjustments and calibrations typical in the stabilization and use of such a new system. In the initial months after implementation, the Department experienced delayed bills in connection with the use of the new system, caused by customer accounts that were missing meter reading information or meeting other exception processing criteria. This resulted in customer bills being held in a queue for manual review and intervention prior to release of such bills. The Department also saw an increase in estimated bills that are sent to customers where metering information was not available. The Department temporarily adjusted its collection practices in light of such concerns. Delayed billing and reduced collection efforts resulted in customer payments below the anticipated levels. The Department implemented a multipart strategy to address these issues, and has seen performance improve significantly on a number of metrics, including substantial reductions in overall value of delayed bills, reductions in the percentage of estimated bills, re-commencement of collections and improved cash collections. Cash collections improved from 91% of expectations in the first seven months of Fiscal Year 2013-14 to 98% of expectations in the last five months of Fiscal Year 2013-14. Cumulative Power System collections in the first six months of the current Fiscal Year 2014-15 were consistent with budgeted amounts. As consumption volumes were slightly higher than budgeted expectations, some collection delays appear to be continuing. The Department has instituted an action plan to assist customers in reducing their delinquent bills. This plan involves introducing new options for customer bill management, resulting from discussions with customers to identify the best billing options for them.

A State audit has been instituted in connection with the implementation of the new customer information system and the billing issues that arose therefrom. The audit field work has been completed and a report is anticipated in early 2015. The Department does not expect that there will be any material impact on the Power System operations or financial condition from the audit. The Department retained a consultant to conduct a review of the new customer information system implementation, and the results of this study were presented to the Board in November 2014. The findings are intended to improve the Department’s future information technology system implementation projects.

Prior to the billing issues discussed above and based on annual historical experience of delinquencies, the Department has been unable to collect approximately 0.7% of the amounts billed to its customers. This amount has potentially increased in connection with the ongoing resolution of the billing issues noted above, as there has been a higher proportion of customer accounts receivable that are considered past due. In light of this, the allowance for doubtful accounts has been increased to
approximately 2.7% of Power System sales for Fiscal Year 2013-14. Power System accounts receivables (including utility user’s tax) as of June 30, 2014 were $426 million compared to $289 million as of June 30, 2013. Of these amounts $277 million (57%) and $91 million (31%), respectively, were considered past due (30 days or more past the payment due date). Due to the billing issues discussed above, the Department suspended its collection activity in November 2013 contributing to this increase in Power System accounts receivable. Commercial collections were recommenced in February 2014 and residential collections were recommenced in June 2014, with both efforts focused on higher balance past due amounts. In an effort to reduce the past due balances, the Department offered a late payment penalty waiver to residential customers if such customers’ balances were paid off by the end of June 2014. Collection efforts have resulted in higher customer contacts with the Department’s call center at certain times, causing increases in call wait times. Accordingly, the intensity of collection efforts has been balanced against these increases in call wait times in order to maintain acceptable customer service levels. As a result of the need to balance these matters, past-due accounts receivable has trended upward during calendar year 2014. By late calendar year 2014, with additional staff deployed at the customer call center, call wait times have been brought close to the targeted and historical levels, and this has permitted the Department to again increase its focus on collection efforts.

The new customer information system provides a platform for future enhancements to improve the customer experience, including levelized (budget) billing, and monthly billing for residential customers, which is under study for potential implementation within the next two years.

THE POWER SYSTEM

General

The Power System is the nation’s largest municipal electric utility with a net maximum plant capacity of 9,251 megawatts (“MWs”) and net dependable capacity of 8,025 MWs as of January 31, 2015, and properties with a net book value of approximately $7.72 billion as of January 31, 2015. The Power System’s highest load registered 6,396 MWs on September 16, 2014. Based on the Department’s April 2014 Retail Electric Sales and Demand Forecast, the Department anticipated that gross customer electricity consumption would increase from Fiscal Year 2012-13 to Fiscal Year 2022-23 at a forecasted rate of approximately 1.2% per year without consideration of the Department’s measures to promote energy efficiency and distributed generation. That load growth rate reflects, in the later part of the ten year planning period, increases due in part to fuel switching in the transportation sector including the increase of plug-in hybrid electric vehicles. In the Power System’s most recent integrated resource plan significant energy efficiency measures are planned for as a cost effective resource, along with support for customer solar projects. This, together with the Board’s adoption in August 2014 of a plan to achieve 15% energy efficiency savings by 2020 are anticipated to result in net overall energy consumption that decreases by 0.17% per year over this period. For the operating statistics of the Power System, see “OPERATING AND FINANCIAL INFORMATION – Summary of Operations.”
The Department estimated that the Power System’s capacity (as of January 31, 2015) and energy mix (actual numbers for calendar year 2013) were approximately as follows:

### DEPARTMENT GENERATION MIX PERCENTAGES

<table>
<thead>
<tr>
<th>Resource Type</th>
<th>Capacity Percentage$^{(1)}$</th>
<th>Energy Percentage$^{(2)}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural Gas</td>
<td>43%</td>
<td>17%</td>
</tr>
<tr>
<td>Large Hydro</td>
<td>19</td>
<td>4</td>
</tr>
<tr>
<td>Coal</td>
<td>18</td>
<td>42$^{(4)}$</td>
</tr>
<tr>
<td>Nuclear</td>
<td>4</td>
<td>10</td>
</tr>
<tr>
<td>Renewables</td>
<td>16</td>
<td>23</td>
</tr>
<tr>
<td>Unspecified Sources of Energy$^{(3)}$</td>
<td>--</td>
<td>4</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>100%</strong></td>
<td><strong>100%</strong></td>
</tr>
</tbody>
</table>

$^{(1)}$ Net Maximum Unit Capability as of January 31, 2015.

$^{(2)}$ Energy percentage is based on the Department’s calendar year 2013 fuel mix submission as part of the 2013 Annual Power Content Label (APCL) to the California Energy Commission in October 2014.

$^{(3)}$ Unspecified sources of energy means electricity from transactions that are not traceable to specific generation sources.

$^{(4)}$ Restoration of one IPP coal generation unit in 2013 after the outage of such unit in 2012 contributed to a higher percentage of coal than in 2012.

The Department anticipates that its generation mix will change in response to statutory and regulatory developments.

**Generation and Power Supply**

The Power System has a number of generating resources available to it. The following discussion describes the Department’s solely owned, jointly owned and contracted generation facilities, as well as fuel and water supplies and spot purchase activities. Currently the Department’s base load requirements are fulfilled primarily by generating capacity at IPP, Navajo Generating Station and PVNGS, and balanced with its natural gas, hydroelectric, renewable resources and spot purchases. The following information concerning the capacities of various facilities is as of January 31, 2015.
Department-Owned Generating Units

The Department’s solely owned generating facilities, as of January 31, 2015, are summarized in the following table:

<table>
<thead>
<tr>
<th>Type of Fuel</th>
<th>Number of Facilities</th>
<th>Number of Units</th>
<th>Net Maximum Capacity (MWs)</th>
<th>Net Dependable Capacity (MWs)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural Gas</td>
<td>4(1)</td>
<td>26</td>
<td>3,474(4)</td>
<td>3,373(4)</td>
</tr>
<tr>
<td>Large Hydro(2)</td>
<td>1</td>
<td>7</td>
<td>1,247</td>
<td>1,175</td>
</tr>
<tr>
<td>Renewables</td>
<td>39</td>
<td>208(3)</td>
<td>433(4)</td>
<td>198(4)</td>
</tr>
<tr>
<td><strong>Subtotal</strong></td>
<td><strong>44</strong></td>
<td><strong>241</strong></td>
<td><strong>5,154</strong></td>
<td><strong>4,746</strong></td>
</tr>
</tbody>
</table>

Less: Payable to the California Department of Water Resources

|                     |                     |                 | (120)(5)                  | (54)(5)                    |
|                     |                     |                 |                           |                            |
| **Total**           | **44**              | **241**         | **5,034**                  | **4,692**                  |

Source: Department of Water and Power of the City of Los Angeles.

(1) Consists of the four Los Angeles Basin Stations (Haynes, Valley, Harbor and Scattergood) discussed and defined below.

(2) The Castaic Plant (as defined below) is undergoing modernization work scheduled to be completed by 2017.

(3) Includes 21 of the hydro units at the Los Angeles Aqueduct, Owens Valley and Owens Gorge hydro units that are certified as renewable resources by the CEC. Also included are microturbine units at the Lopez Canyon Landfill and Department built photovoltaic solar installations, the Pine Tree Wind Project, and the Linden Wind Energy Project, and a local small hydro plant. Not included are the units that were upgraded at the Castaic Plant or the two Scattergood Generating Station gas-fueled units that partially burn digester gas.

(4) Included as Renewables and excluded from Natural Gas are the 16 MWs of renewable energy generated at the Scattergood Generating Station by the burning of digester gas from the Hyperion Sewage Treatment Plant.

(5) Energy payable to the California Department of Water Resources for energy generated at the Castaic Plant. This amount varies weekly up to a maximum of 120 MWs.

Los Angeles Basin Stations. The Department is the sole owner and operator of four electric generating stations in the Los Angeles Basin (the “Los Angeles Basin Stations”), with a combined net maximum generating capacity of 3,474 MWs and a combined net dependable generating capacity of 3,373 MWs. Natural gas and digester gas are used as fuel for the Los Angeles Basin Stations. Low-sulfur, low-ash residual distillate is used for emergency back-up fuel. See “—Fuel Supply for Department-Owned Generating Units and Apex Power Project.” See also “—Projected Capital Improvements.”

Haynes Generating Station. The largest of the Los Angeles Basin Stations is the Haynes Generating Station, located in the City of Long Beach, California. The Haynes Generating Station currently consists of eleven generating units with a combined net maximum capacity of 1,639 MWs and a net dependable capacity of 1,585 MWs. A Haynes Generating Station combined-cycle generating unit includes two combustion turbines and a common steam turbine. The combustion turbines can each operate with the steam turbine independently or together in a two -on -one configuration (and are counted by the Department as three generating units). In July 2013, the Department completed the repowering of units 5 and 6 with six advanced simple-cycle gas turbine units. See “— Environmental Regulation and Permitting Factors – Water Quality – Cooling Water Process – State Water Resources Control Board” and “— Regional Requirements – Thermal Discharges at Harbor Generating Station and Haynes Generating Station” for a discussion of potential permitting and related equipment upgrades with respect to cooling water intake structures and thermal discharges.
Valley Generating Station. The Valley Generating Station is located in the San Fernando Valley and is comprised of a simple-cycle generating turbine unit and a combined-cycle generating unit consisting of two gas turbines with heat recovery steam generators, which supplies one steam turbine (counted as three units) with 576 MWs of net maximum capacity. The total net dependable capacity for the Valley Generating Station is 556 MWs.

The Valley Generating Station also has 50 microturbines located at the Lopez Canyon Landfill in the hills above the City of Sun Valley. The microturbines burn the excess landfill gas and have a 1.5 MWs total combined net capacity. The microturbines are not operational at this time due to insufficient landfill gas production from the Lopez Canyon landfill.

Harbor Generating Station. The Harbor Generating Station is located in Wilmington, California. The Harbor Generating Station is comprised of a combined-cycle generating unit (counted as three units) and five additional peaking combustion turbines for a total of eight generating units. The Harbor Generating Station’s net maximum capacity is 458 MWs with a net dependable capacity of 452 MWs. See “— Environmental Regulation and Permitting Factors – Water Quality – Cooling Water Process – State Water Resources Control Board” and “- Regional Requirements –Thermal Discharges at Harbor Generating Station and Haynes Generating Station” for a discussion of potential permitting and related equipment upgrades with respect to cooling water intake structures and thermal discharges.

Scattergood Generating Station. The Scattergood Generating Station is located near El Segundo, California and is comprised of three steam generating units with a net maximum capacity of 817 MWs from natural gas and a net dependable capacity of 796 MWs from natural gas. Included in the above-referenced figures is 16 MWs of net capacity that can produced from the burning of digester gas from the adjacent Hyperion Sewage Treatment Plant in units 1 and 2. The Department plans to repower 460 MWs of Scattergood Generating Station with a combined-cycle generating unit and two simple-cycle gas turbine units by December 2015. See “— Environmental Regulation and Permitting Factors – Water Quality – Cooling Water Process – State Water Resources Control Board” for a discussion of potential permitting and related equipment upgrades with respect to cooling water intake structures.

Once-Through-Cooling. The Haynes Generating Station, the Harbor Generating Station and the Scattergood Generating Station use the once-through-cooling process in order to provide cooling in each plant. Once-through-cooling is the process where water is drawn from a source, pumped through equipment at a power plant to provide cooling and then discharged. A cooling process is necessary for nearly every type of traditional electrical generating station and the once-through-cooling process is used by many electrical generating stations located next to large bodies of water. In once-through-cooling, the water is not chemically changed in the cooling process; however the water temperature can increase. The water drawn into the intake and the thermal discharges are regulated by the federal Clean Water Act and similar state law.

EPA Requirements. On April 20, 2011, the EPA publicly posted for a comment period a new proposed rule related to Section 316(b) of the Clean Water Act (“Rule 316(b)”) in the Federal Register, proposing requirements for cooling water intake structures for all existing power generating facilities that withdraw more than two million gallons per day of water from waters of the United States and use at least 25% of the water they withdraw exclusively for cooling purposes, and is a point source. Rule 316(b) was signed by the EPA on May 16, 2014 and became effective on October 14, 2014. Under the rule, an owner or operator of an existing facility will be able to choose from seven different options to comply with impingement mortality (“IM”). For entrainment mortality (“EM”), entrainment studies must be performed along with evaluations of entrainment technologies. The Department has determined it will comply with IM and EM by replacing once-through-cooling with closed cycle cooling by 2029. The Department’s permitting authority, the State Water Resources Control Board, has approved the
Department’s IM and EM compliance proposal and has granted, after a public hearing, an extended compliance schedule until 2029.

State Water Resources Control Board. The State Water Resources Control Board’s statewide policy with respect to the Clean Water Act Section 316(b) became effective on October 1, 2010 when published as Section 2922 of Title 23 of the California Code of Regulations (“Regulation Section 2922”). The new regulation requires all facilities subject to the Clean Water Act Section 316(b) to either use Track 1, which requires the use of closed cycle cooling or flow reduction commensurate to that of closed cycle cooling – a minimum of 93% flow reduction; or Track 2, which entails demonstrating that Track 1 is infeasible and requires compliance measured on a unit by unit basis with the use of “alternate” technologies where IM and entrainment reduction must be 83.7%. In the interim, Regulation Section 2922 requires the installation of large organism exclusion devices and the cessation of intake flows if not engaging in power-generating activities or critical system maintenance. The owner or operator of such facilities must further mitigate any interim impacts commencing five years after the effective date of Regulation Section 2922 until final compliance is achieved. The Department owns three coastal generating stations that utilize once-through-cooling, that provide approximately 85% of the Department’s in-basin generation and 39% of the total generating plant capacity owned by the Department, which are subject to the new Regulation Section 2922.

On July 19, 2011, the State Water Resources Control Board adopted an amendment to Regulation Section 2922 that accelerated the compliance dates for three coastal units and extended the compliance dates until 2024 for two coastal units and 2029 for the remaining four coastal units. The new compliance schedule allows for both grid reliability and a financially sustainable path forward while making the equipment upgrades necessary to remove the coastal generating stations’ units from utilizing once-through-cooling. The total estimated outlay for the accelerated schedule of compliance by 2020 would have cost approximately $2.2 billion.

Regional Requirements – Thermal Discharges at Harbor Generating Station and Haynes Generating Station. The State Water Resources Control Board’s Water Quality Control Plan for Control of Temperature in the Coastal and Interstate Waters and Enclosed Bay and Estuaries of California (the “California Thermal Plan”) has different thermal criteria for discharges into estuaries and bays than it does for discharges into the ocean. The water discharges from Harbor Generating Station and Haynes Generating Station were originally permitted as ocean discharges. In January 2003, however, the Los Angeles Regional Water Quality Control Board (“LARWQCB”) informed the Department that it (i) reclassified the Harbor Generating Station discharge as an enclosed bay discharge and that (ii) it intends to reclassify the Haynes Generating Station discharge as an estuary discharge. Accordingly, the Harbor Generating Station NPDES permit was renewed by the LARWQCB in July 2003, with the new enclosed bay classification and the associated, more stringent, permit limits. Based on the notice of intent to reclassify the Haynes Generating Station discharge and planned changes to be made to the Haynes Generating Station’s flow volume, the Department has completed a hydrological model of the Lower San Gabriel River. Haynes discharges into the San Gabriel River, which in turn flows into the ocean. The hydrological study was designed to evaluate the accuracy of the LARWQCB’s claim that Haynes Generating Station discharges into an estuary and concluded that the estuary classification is not accurate. The Department has submitted objections to the proposed permit reclassification and they are currently pending before the LARWQCB. If the Department’s objections are unsuccessful and the Haynes Generating Station discharge is reclassified as an estuarine discharge, the Haynes Generating Station would be unable to comply with the California Thermal Plan without a permit variance. If the Department is unable to obtain a permit variance, the Haynes Generating Station facility could be limited or unable to operate.
Castaic Pump Storage Power Plant. The Castaic Pump Storage Power Plant is located near Castaic, California (the “Castaic Plant”) at the terminus of the west branch of the California Aqueduct. The Castaic Plant is the Department’s largest source of hydroelectric capacity and consists of seven units. The Castaic Plant’s net dependable capacity for the seven units is 1,175 MWs, however the Castaic Plant is capable of generating 1,247 MW for short periods of time, or extended periods of time if sufficient flow-through water schedules are received. The units are currently being rotated out of service for modernization resulting in a reduced net dependable capacity of 1,175 MWs during the modernization process. The Department intends that other units at the Castaic Plant, in turn, will be rotated out of service for modernization. The modernization process is expected to continue through June 2017. See “Projected Capital Improvements.” This refurbishment is projected to add up to 80 MWs of capacity. FERC licenses pursuant to which the Department operates the Castaic Plant expire in 2022. The Castaic Plant provides peaking and reserve capacity and is normally not a source of energy to the Department’s net base load requirements. The Castaic Plant obtains water supply via the water conveyance system (the “State Water Project”) operated by the California Department of Water Resources, which has been the subject of recent litigation to which the Department is not a party (Cal Trout, et al. v. State Water Resources Control Board, Sacramento County Superior Court Case No. 34-2009-00031461-CU-WM-GDS). It has been alleged that the California Department of Water Resources is illegally “taking” listed species of fish through operation of the State Water Project export facilities and that the California Department of Water Resources should cease operation of the State Water Project pumps. The California Department of Water Resources has altered the operations of the State Water Project to accommodate the listed species, which has had the effect of reduced pumping from the affected waters. Success by plaintiffs in this litigation could influence how the State Water Project is operated and further reduce water flow to the Castaic Plant. The Department cannot predict at this time what effect this litigation will have on the Power System. Recent drought conditions in the State are expected to result in reduced energy production from the Castaic Plant, however, such reduction is not expected to have a material adverse effect on the operations of the Power System because of the increased use of alternate resources such as renewables and natural gas. See “Water Supply for Department-Owned Generating Units” below.

Owens Gorge and Owens Valley Hydroelectric Generation. The Owens Gorge (the “Owens Gorge Hydroelectric Generation”) and Owens Valley Hydroelectric generating units (the “Owens Gorge and Owens Valley Hydroelectric Generation”) are located along the Owens Valley in the Eastern High Sierra region of California. The aggregate net dependable capacity of Owens Gorge and Owens Valley Hydroelectric Generation totals 111 MW. Owens Gorge Hydroelectric Generation consists of three units (Upper Gorge, Middle Gorge, and Control Gorge) and Owens Valley Hydroelectric Generation consists of seven units (Haiwee 1 and 2, Cottonwood 1 and 2, Division Creek, Big Pine, and Pleasant Valley), providing a net dependable capacity of 109.5 MW and 1.2 MW, respectively.

The Owens Gorge and Owens Valley Hydroelectric Generation is a network of hydroelectric plants which use water resources of the Los Angeles Aqueduct and three creeks along the Eastern Sierras. The water flow fluctuates from year to year and as a result water flow may be reduced from seasonal norms from time to time. Since 1998 the total aqueduct exports from Owens Valley to the City have gone from approximately 457,000 acre-feet per year to currently 223,000 acre-feet per year. This difference is due to environmental uses in the Owens Valley, including Mono Lake level restoration, Lower Owens River restoration, reduced groundwater pumping and Owens Lake dust mitigation. Consequently, this water use reallocation has resulted in a reduction of downstream hydroelectric generation, which is accounted for in the annual updates of the Power System’s integrated resource plan; however, due to a recent settlement relating to the Owens Lake dust mitigation that allows for waterless dust
control methods to be used, less water obtained through aqueduct exports may be used for environmental uses in the future and may result in increased aqueduct exports from Owens Valley to the City. In addition, limits on water flow resulting from a permanent injunction agreed to in January 2015 concluding certain litigation may lead to the reduction of downstream hydroelectric generation. See “LITIGATION – Owens Gorge” for details of such litigation. Recent drought conditions in the State are expected to result in reduced energy production from the Owens Gorge and Owens Valley Hydroelectric Generation, however, such reduction is not expected to have a material adverse effect on the operations of the Power System. A reconditioning and refurbishment to selected components of the Owens Gorge Hydroelectric Generation units is ongoing and it is expected to extend the life of the three units, increase reliability, and improve efficiency of such units.

San Francisquito Canyon and the Los Angeles and Franklin Reservoirs. The Department also owns and operates eleven units located north of the City along the Los Angeles Aqueduct in San Francisquito Canyon and at the Los Angeles and Franklin Reservoirs. The net aggregate dependable plant capacity of these smaller units is 24.2 MWs under average water conditions. For a description of litigation arising out of a fire that started near San Francisquito Canyon, see “LITIGATION – Powerhouse Fire.”
Jointly-Owned Generating Units and Contracted Capacity Rights in Generating Units

The Department has additional generating resources available as capacity rights resulting from undivided ownership interests in facilities that are jointly-owned with other utilities. These interests, as of January 31, 2015, are summarized in the following chart and discussed below. Each project participant with respect to jointly-owned units is responsible for providing its share of construction, capital, operating and maintenance costs.

<table>
<thead>
<tr>
<th>Type</th>
<th>Number of Facilities</th>
<th>Department’s Net Maximum Capacity Entitlement (MWs)</th>
<th>Department’s Net Dependable Capacity Entitlement (MWs)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td>2</td>
<td>1,679&lt;sup&gt;(1)&lt;/sup&gt;</td>
<td>1,679</td>
</tr>
<tr>
<td>Natural Gas</td>
<td>1</td>
<td>532</td>
<td>480</td>
</tr>
<tr>
<td>Large Hydro</td>
<td>1</td>
<td>491&lt;sup&gt;(2)&lt;/sup&gt;</td>
<td>455</td>
</tr>
<tr>
<td>Nuclear</td>
<td>1</td>
<td>387&lt;sup&gt;(3)&lt;/sup&gt;</td>
<td>380</td>
</tr>
<tr>
<td>Renewables/Distributed</td>
<td>14,953&lt;sup&gt;(4)&lt;/sup&gt;</td>
<td>1,008</td>
<td>285</td>
</tr>
<tr>
<td>Generation (“DG”)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>14,958</strong></td>
<td><strong>4,097</strong></td>
<td><strong>3,279</strong></td>
</tr>
</tbody>
</table>

Source: Department of Water and Power of the City of Los Angeles.

<sup>(1)</sup> The Department’s IPP entitlement is 48.62% of the maximum net plant capacity of 1,800 MWs. An additional 18.17% portion of the IPP entitlement is subject to variable recall as set forth under “Intermountain Power Project – Power Recalls” below. The Department’s Navajo Generating Station entitlement is 21.20% of the maximum net plant capacity of 2,250 MWs. See “Intermountain Power Project” and “Navajo Generating Station” below.

<sup>(2)</sup> The Department’s Hoover Power Plant contract entitlement is 491 MWs, 25.16% of the Hoover total contingent capacity. As of July 2014, reduced lake levels have reduced the Department’s dependable capacity to approximately 455 MWs. See “Hoover Power Plant” below.

<sup>(3)</sup> The Department’s PVNGS entitlement is 9.66% of the maximum net plant capacity of 4,003 MWs. See “Palo Verde Nuclear Generating Station” below.

<sup>(4)</sup> The Department’s contract renewable resources in-service include landfill gas units at various landfills in the Los Angeles area; biogas fuel purchases out of state; hydro unit locally; wind farms in Oregon, Washington, Utah and Wyoming; and customer solar photovoltaic installations and DG units located in the Los Angeles region.

Intermountain Power Project.

General. The IPP consists of: (i) a two-unit coal-fired steam-electric generating plant with a net rating of 1,800 MW (the “Intermountain Generating Station”) and a switchyard (the “Switchyard”), located near Lynndyl, in Millard County, Utah; (ii) a ±500 kV direct current transmission line approximately 490 miles in length from and including the Intermountain Converter Station (an alternating current/direct current converter station adjacent to the Switchyard) to and including a corresponding converter station at Adelanto, California (collectively, the “Southern Transmission System”) (see “Transmission and Distribution Facilities – Southern Transmission System”); (iii) two 50-mile, 345 kV, alternating current transmission lines from the Switchyard to the Mona Switchyard in the vicinity of Mona, Utah and a 144-mile, 230 kV, alternating current transmission line from the Switchyard to the Gonder Switchyard near Ely, Nevada (collectively, the “Northern Transmission System”); (iv) a microwave communications system; (v) a railcar service center located in Springville, in Utah County, Utah (the “Railcar Service Center”); and (vi) certain water rights and coal supplies (which water rights and coal supplies, together with the Intermountain Generating Station, the Switchyard and the Railcar Service Center, are referred to herein collectively as the “Generation Station”). Pursuant to a Construction Management and Operating Agreement between IPA and the Department, IPA appointed the Department as project manager and operating agent responsible for, among other things, administrating, operating and maintaining the IPP. All of the facilities of IPP have been in full commercial operation since May 1, 1987 and have operated at higher than anticipated capacity and availability levels.
**Power Contracts.** Pursuant to a Power Sales Contract with IPA (the “IPP Contract”) and a Lay-Off Power Purchase Contract with Utah Power & Light Company (now operating as Rocky Mountain Power, “UP&L”) and IPA, the Department is entitled to 44.617% of the capacity of the IPP (currently equal to 803 MWs). The existing IPP Contract terminates in 2027 and contains provisions that allow renewal by the Department under certain circumstances, subject to legal and regulatory mandates. SB 1368 prohibits the Department from making any “long-term financial commitment” in connection with “baseload generation” that does not satisfy the greenhouse gas emissions performance standard specified in the bill. Accordingly, the existing IPP contract cannot be renewed by the Department in its current form.

Pursuant to the IPP Contract, the Department is required to pay in proportion to its entitlement share the costs of producing and delivering electricity as a cost of purchased capacity. The Department also has available additional capacity in the IPP through an excess power sales agreement with certain other IPP participants (the “IPP Excess Power Sales Agreement”). Under the IPP Excess Power Sales Agreement the Department is entitled to 18.168% of the capacity of IPP (currently equal to approximately 327 MWs). Pursuant to a Power Purchase Agreement with UP&L (the “UP&L Contract”), the Department purchases capacity and energy equivalent to the capacity and energy made available to UP&L pursuant to its 4% entitlement in the IPP (currently equal to approximately 72 MWs) until 2027, subject to certain renewal rights which are dependent upon certain factors including the renewal of the IPP Contract. Under the UP&L Contract, the Department is obligated to pay to UP&L amounts equal to the amounts UP&L is required to pay IPA under its contract with IPA with respect to the IPP. The IPP Contract and UP&L Contract require the Department to pay for such capacity and energy on a “take-or-pay” basis as operating expenses of the Power System. See “OPERATING AND FINANCIAL INFORMATION – Take-or-Pay Obligations.”

In Fiscal Year 2013-14, the IPP operated at a plant capacity factor of 78.37% and provided approximately 7.9 million megawatt-hours (“MWhs”) of energy to the Power System.

**Intermountain Generating Station upon the termination of the IPP Contract.** The Department has been in discussions with IPA and other IPP power purchasers with respect to providing for the sale of the generation and transmission entitlements of IPP following the termination of the IPP Contract in 2027. In order to facilitate the continued participation of the Department and other State power purchasers in the IPP, the IPA Board has issued the Second Amendatory Power Sales Contract that would amend the current Power Sales Contract and allow the plant to replace the coal units with combined cycle natural gas units by July 1, 2025. IPA and the Department have also prepared draft Renewal Power Sales Contracts to continue taking power from the Intermountain Generating Station fueled by natural gas for the period of 2027 through 2077. The Board and City Council have approved the Second Amendatory Power Sales Contract. The Department awaits similar approvals of the Second Amendatory Power Sales Contracts from the other IPP power purchasers. The Second Amendatory Power Sales Contracts would only take effect upon approval by all the IPP power purchasers. The Department is exploring many options with respect to the termination of the IPP Contract and its exit from coal fired power plants. The Department is currently evaluating the financial impact of these several options on the finances and operations of the Department.

**Power Recalls.** Certain IPP participants have a right under the IPP Excess Power Sales Agreement to recall from the Department up to 18.168% of the capacity of IPP (currently equal to approximately 327 MWs) for defined future summer or winter seasons or both, following no less than 90 days’ notice and up to 43 MWs of such capacity on a seasonal basis following no less than 90 days’ notice. No MWs of capacity were recalled, as of September 25, 2014, for the 2014-15 winter season from the Department. The Department can give no assurance that the capacity of IPP subject to recall from the Department under the Excess Power Sales Agreement will not be recalled.
Fuel Supply. The Department, in its role as the operating agent of IPP, buys coal under contracts to fulfill the supply requirement of approximately 5.5 million tons per year. Coal is purchased under a diversified portfolio of fixed price contracts that are of short-, medium- and long-term in duration. From now through 2016, the Department has determined that coal presently under contract is sufficient, with the exercise of available options, to meet the IPP’s annual coal requirements, with lesser amounts of coal under contract thereafter. The average cost of coal delivered to the Intermountain Generating Station in Fiscal Year 2013-14 was approximately $47.53 per ton. During the prior Fiscal Year, the average cost of coal delivered was approximately $47.62 per ton. The Department expects the costs to fulfill IPP’s annual coal supply requirements after 2015 may be higher than its current contract costs due to the continual turnover of mining properties in Utah, difficult mining conditions at the remaining mines, increased mining costs due to regulatory oversight, and the continued increase in rail transportation costs, among other things. To be able to continue to operate the IPP in the event of a coal supply disruption, IPA attempts to maintain a coal stockpile at the Intermountain Generating Station that is sufficient to operate the plant at the IPP’s current plant capacity factors for a minimum of 60 days. Transportation of coal to the Intermountain Generating Station is provided primarily by rail under agreements between IPA and the Utah Railway and the Union Pacific Railroad companies, and the coal is transported in IPA-owned railcars. Coal is also transported to IPP, to some extent, in commercial trucks.

Navajo Generating Station.

General. The Navajo Generating Station is a coal-fired, electric generating station and consists of three units with a combined capacity of 2,250 MWs located near the City of Page, Arizona. Salt River Project is the operating agent for the Navajo Generating Station. The Department has a 21.2% ownership interest in the Navajo Generating Station, and the Department’s share of the Navajo Generating Station capacity amounts to 477 MWs. The existing co-tenancy agreement related to the lease of the facilities terminates in 2019 and may be renewed as provided in such co-tenancy agreement. In response to SB 1368, the Department is negotiating the divestiture of its ownership interest in the Navajo Generating Station. The Power System’s most current integrated resource plan recommends that the sale of the Department’s ownership interest in the Navajo Generating Station occur in 2015. The timing of the sale will depend on a variety of factors within and outside of the control of the Department, including the impact of the Best Available Retrofit Technology (“BART”) final action, as discussed below. The Department’s efforts to sell its share of the Navajo Generating Station are ongoing and the Department cannot give any assurance as to if or when a divestiture transaction will occur.

Water Supply. The Navajo Generating Station uses water from nearby Lake Powell for cooling purposes, pursuant to a Water Service Contract with the United States of America. As a result of drought conditions in the Southwest United States over the last several years, water levels in Lake Powell have dropped significantly at various points and may ultimately fall below the former pipeline intake for the Navajo Generating Station. In order to mitigate this issue, the pipeline was relocated in 2009 to a position at which intake is possible at lower elevations.

Environmental Considerations. The visual range, or visibility impairment, at national parks and wilderness areas is affected by natural and human-caused sources of air pollution. The visibility program of the United States Environmental Protection Agency (the “EPA”) arising from the federal Clean Air Act requires states to address visibility impairment caused by pollutants from certain large industrial sources through a process to establish BART. The Navajo Generating Station has installed pollution control equipment that significantly reduced sulfur dioxide emissions and particulate matter in order to protect visibility and improve air quality. A BART review process was conducted by the EPA to set the level of nitrogen oxide (“NOx”) emissions allowed for the Navajo Generating Station as well as the proper emissions control technology. On August 8, 2014, the Federal Register noticed the EPA’s final source-specific implementation plan requiring the Navajo Generating Station, through the application of BART, to achieve over an 80% reduction of its current overall NOx emission rate. On November 4, 2014, the
Federal Register noticed the EPA’s proposed “Carbon Pollution Guidelines for Existing Stationary Sources: EGUs in Indian Country and U.S. Territories,” which includes the Navajo Generating Station. In the proposal, the EPA states that the Navajo Nation is expected to meet the proposed CO₂ goals through compliance with other regulations, such as the Navajo Generating Station’s Federal Implementation Plan. The EPA has announced that it expects to finalize this regulation in the summer of 2015.

**Mohave Generating Station.**

**General.** The Mohave Generating Station is located near Laughlin, Nevada. It was a coal-fired electric generating station, consisting of two units with a combined capacity of 1,580 MWs. The Department owns a 10% interest in the Mohave Generating Station. The other co-owners are Southern California Edison Company (“Edison”), Salt River Project and the NV Energy (formerly known as Nevada Power Company).

**Operations Ceased.** The Mohave Generating Station generating units were removed from service at the end of 2005. There are currently no plans to return the Mohave Generating Station to service as a coal-fired facility. Staff has been reduced and all major plant decommissioning was completed in 2012. Minor cleanup, ground water monitoring and upkeep of the plant site will continue for a number of years after the decommissioning to ensure that the integrity of the coal ash landfill is maintained and that the groundwater is protected from contamination.

**Apex Power Project.**

The Apex Power Project (the “Apex Power Project”) is located in unincorporated Clark County, north of Las Vegas, Nevada. The Apex Power Project includes one combined cycle generating station consisting of one steam turbine generator, and two simple cycle, 165 MW, combustion turbine generators. The Apex Power Project also includes heat recovery equipment, air inlet filtering, closed cycle cooling system, emission control system, exhaust stack, distributed control system, and all necessary noise control equipment. The Apex Power Project is an existing power plant with a net maximum capacity of 532 MWs and a net dependable capacity of 480 MWs. The Department completed the purchase through a take-or-pay contract with SCPPA of 100% of the capacity and energy of the Apex Power Project on March 25, 2014. See “OPERATING AND FINANCIAL INFORMATION – Take-or-Pay Obligations.”

**Hoover Power Plant.**

**General.** The Hoover Power Plant is located on the Arizona-Nevada border approximately 25 miles east of Las Vegas, Nevada and is part of the Hoover Dam facility, which was completed in 1935 and controls the flow of the Colorado River. The Hoover Power Plant consists of 17 generating units and two service generating units with a total installed capacity of approximately 2,074 MWs. The Department has a power purchase agreement with the United States Department of Energy Western Area Power Administration for 491 MWs of capacity (calculated based on 25.16% of 1,951 MWs of total contingent capacity) and energy from the Hoover Power Plant through September 2017. Due to the enactment of H.R. 470, “Hoover Power Allocation Act of 2011,” the Department expects to be allocated 496 MWs of capacity (calculated based on 23.92% of 2,074 MWs of total contingent capacity) and energy from the Hoover Power Plant from October 2017 through September 2067. The facility is owned and operated by the United States Bureau of Reclamation.

**Drought Conditions.** Because of prolonged drought conditions that have resulted in record low lake levels, the Department’s capacity entitlement at the Hoover Power Plant has been reduced from time to time. Recent drought conditions have resulted in lower water levels and are expected to result in a material adverse effect on the Hoover Power Plant’s capacity entitlement in the near future. According to its February 2015 24-month study, the United States Bureau of Reclamation forecasts relatively stable
water levels and Hoover Power Plant capacity, with the lowest point forecasted to occur in November 2016, with a total Hoover Power Plant capacity of 930.2 MWs and a 61% generating unit availability.

Environmental Considerations. The lower Colorado River has been included in a critical Habitat Designated Area. This required the Bureau of Reclamation to prepare and file with the United States Fish and Wildlife Service a Biological Assessment on the effect of its operations of the lower Colorado River on endangered species therein. After the Biological Assessment was filed, the United States Fish and Wildlife Service issued a Biological and Conference Opinion regarding the Bureau of Reclamation’s operations and outlined remedial actions to be taken to correct adverse effects to endangered species. Such remedial actions could affect the operation of the Hoover Power Plant, which would in turn affect the Hoover Power Plant customers, including the Department. The Department believes that any impact on future operations will be minor; however there is a possibility that major remediation actions could have a material impact on the Hoover Power Plant customers’ available capacity from the Hoover Power Plant. The Hoover Power Plant customers, including the Department, together with certain other parties, have implemented a plan in cooperation with the Bureau of Reclamation and the United States Fish and Wildlife Service to mitigate negative effects on the Hoover Power Plant’s energy production.

Palo Verde Nuclear Generating Station.

General. PVNGS is located approximately 50 miles west of Phoenix, Arizona. PVNGS consists of three nuclear electric generating units (numbered 1, 2 and 3), with a net maximum capacity of 1,333 MWs (unit 1), 1,336 MWs (unit 2) and 1,334 MWs (unit 3) and a dependable capacity of 1,311 MWs (unit 1), 1,314 MWs (unit 2) and 1,312 MWs (unit 3). PVNGS’s combined design capacity is 4,003 MWs and its combined dependable capacity is 3,937 MWs. Each PVNGS generating unit has been operating under 40-year Full-Power Operating Licenses granted by the Nuclear Regulatory Commission (the “NRC”). In April 2011, the NRC approved PVNGS’s license renewal application, allowing the three units to extend operation for an additional 20 years until 2045, 2046 and 2047, respectively. The Department obtained Board and City Council approval to renew the participation agreement for PVNGS in January 2014. Arizona Public Service Company (“APS”) is the operating agent for PVNGS. For Fiscal Year 2013-14, PVNGS provided over 3.0 million MWhs of energy to the Power System, representing approximately 11% of the Department’s overall energy for this period. The Department has a 5.7% direct ownership interest in the PVNGS (approximately 224 MWs of dependable capacity). The Department also has a 67.0% generation entitlement interest in the 5.91% ownership share of PVNGS that belongs to SCPPA through its “take-or-pay” power contract with SCPPA (totaling approximately 156 MWs of dependable capacity), so that the Department has a total interest of approximately 380 MWs of dependable capacity from PVNGS. Co-owners of PVNGS include APS; the Salt River Project Agricultural Improvement and Power District, a political subdivision of the state of Arizona, and the Salt River Valley Water Users’ Association, a corporation (together, the “Salt River Project”); Edison; El Paso Electric Company; Public Service Company of New Mexico; SCPPA and the Department.

Nuclear Regulatory Commission. The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. Events at nuclear facilities of other operators or impacting the industry generally may lead the NRC to impose additional requirements and regulations on existing and new facilities. As a result of the March 2011 earthquake and tsunami that caused significant damage to the Fukushima Daiichi Nuclear Power Plant in Japan, various industry organizations are working to analyze information from the Japan incident and develop action plans for U.S. nuclear power plants. Additionally, the NRC is performing its own independent review of the events at Fukushima Daiichi, including a review of the agency’s processes and regulations in order to determine whether the agency should promulgate additional regulations and possibly make more fundamental changes to the NRC’s system of regulation.
On March 12, 2012, the NRC issued the first regulatory requirements for all 104 operating reactors located in the United States based on the task force evaluations. The NRC issued three orders that modify operating licenses by requiring the following safety enhancements: (1) mitigation strategies to respond to extreme natural events resulting in the loss of power at plants, (2) ensuring reliable hardened containment vents, and (3) enhancing spent fuel pool instrumentation. The orders require prompt implementation of the safety enhancements and to complete implementation within two refueling outages or by December 31, 2016, whichever comes first. The NRC also issued a request for information, requesting that each reactor operator reevaluate seismic and flooding hazards at its site using present-day methods and information, conduct walkdowns of its facilities to ensure protection against the hazards in its current design basis, and reevaluate emergency communications systems and staffing levels. On March 20, 2012, the NRC published an advanced notice of public rulemaking related to station blackout conditions. On April 18, 2012, the NRC published an advanced notice of public rulemaking related to strengthening and integrating onsite emergency response capabilities. On May 31, 2012, the NRC staff issued guidance with respect to assessing emergency preparedness communications and staffing and performing seismic and flooding walkdowns. On July 13, 2012, the NRC staff provided the Commission with a paper outlining its proposed actions on the remaining recommendations. On August 30, 2012, the NRC issued implementation guidance for each of the orders issued in March 2012. On January 4, 2013, the NRC issued guidance to enable U.S. nuclear power plant operators to perform the seismic and flooding hazard assessments, which was done at PVNGS in September 2014.

The NRC has required PVNGS to increase the redundancy in its power supply to emergency cooling systems, reinforce its spent fuel pool, accelerate the transfer of spent fuel from the pool to the dry cask storage, and add pipelines and associated equipment necessary for supplying additional cooling water to the reactors. As of the date of this Official Statement, PVNGS has purchased additional diesel generators, pumps and fire trucks, and has also accelerated the movement of its spent fuel casks to the storage facility. In addition to these actions, PVNGS has allotted approximately $82.2 million (approximately $4.7 million for the Department) for initiatives developed in response to the failure at the Fukushima power plant in Japan, which initiatives include, among other things, fuel building modifications, an emergency equipment storage facility, temporary power connections, seismic and flood hazards validation and corresponding mitigating strategies. Additional NRC-mandated requirements are anticipated, but the costs associated with these future projects are unknown at this time.

In the event of noncompliance with its requirements, the NRC has the authority to impose monetary civil penalties or a progressively increased inspection regime that could ultimately result in the shut-down of a unit, or both, depending upon the NRC’s assessment of the severity of the situation, until compliance is achieved. The increased costs resulting from penalties, a heightened level of scrutiny and implementation of plans to achieve compliance with NRC requirements may adversely affect the Department’s financial condition, results of operations and cash flows.

Construction and Maintenance. PVNGS capital projects during the next 10 years are expected to include a cyber security upgrade, a cooling tower life extension project, a generator excitation system upgrade, equipment replacement or upgrades such as reactor coolant pump motor replacements and generator stator rewinds, building upgrades and other miscellaneous projects. Such projects are expected to cost the Department approximately $110 million over this 10 year period.

Decommissioning Costs. The owners of PVNGS have created external trusts in accordance with the PVNGS participation agreement and NRC requirements to fund the costs of decommissioning PVNGS. Based on a 2013 estimate of decommissioning costs, which uses the extended license expiration date of 2047 and is the most recent estimate available, the Department estimates that its share of the amount required for decommissioning PVNGS relating to the Department’s direct ownership interest in PVNGS was approximately 89% funded and that its share of decommissioning costs through SCPPA was 116% funded. The Department’s direct share of costs is $137.3 million and SCPPA’s share is $142.4
million, of which the Department’s portion is $95.4 million or 67%. Under the current funding plan, the Department estimates that its share of the decommissioning costs relating to the Department’s direct ownership interest in PVNGS will be fully funded by accumulated interest earnings by the extended license expiration date of 2047. Such estimates assume 7% per annum in future investment returns and a 5% per annum cost escalation factor. The Department has received and is receiving less than a seven percent investment return on the decommissioning funds. No assurance or guarantee can be given that investment earnings will fully fund the Department’s remaining decommissioning obligations at current estimated costs or that the decommissioning costs will not exceed current estimates. For a discussion of the Department’s nuclear decommissioning trust fund and other investments held on behalf of the Department, see “THE DEPARTMENT – Investment Policy and Controls.”

### Nuclear Waste Storage and Disposal

Generally, federal and state efforts to provide adequate interim and long-term storage facilities for low-level and high-level nuclear waste have proven unsuccessful to date. Although federal and state efforts continue with respect to such storage and disposal facilities, the Department is not able to predict the schedule for the permanent disposal of radioactive wastes generated at PVNGS. APS, which currently stores spent nuclear fuel in on-site pools near the units, has advised the Department that until a permanent repository for high-level nuclear waste developed by the federal government becomes available, additional on-site spent fuel storage is required by using dry casks similar to those currently used at other nuclear plants. Since the spent fuel pools ran out of storage capacity, an independent spent fuel storage installation was built to provide additional spent fuel storage at the site while awaiting permanent disposal at a federally developed facility. The installation uses dry cask storage and was designed to accept all spent fuel generated by PVNGS during its lifetime. As of January 31, 2015, 124 casks, each containing 24 spent fuel assemblies, have been stored. If it is ever required, the on-site storage facility can be expanded from its current size to accommodate additional waste. APS estimates that the storage facility has sufficient storage capacity to store all low-level radioactive waste produced at PVNGS until the end of operation of PVNGS. Since the event at the Fukushima Daiichi nuclear power plant, PVNGS embarked on a program to accelerate the transfer of spent fuel from the spent fuel pools to the dry cask storage facility, thus reducing the heat load inside the spent fuel pools. In addition, beginning in 2016, PVNGS is expected to use the newly designed casks that contain 36 spent fuel assemblies allowing the dry cask storage facility to accept more spent fuel. Storage costs are partially paid using funds received by APS pursuant to a settlement agreement with the United States government relating to nuclear waste disposal fees.

### Renewable Power Initiatives

The Department expects to procure 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 (“AB32”). For a discussion of certain State legislation and regulations affecting the Department, including AB32, SB 1368, and SBX1-2 see “DEVELOPMENTS IN THE CALIFORNIA ENERGY MARKETS” in the forepart of this Official Statement. Certain components of the Department’s renewable power resource portfolio are described below. Wind power, both obtained through power purchase agreements and resources owned by the Department, provided 13% and 14% of the Department’s energy in 2012 and 2013 respectively, or just over one-half of the renewable energy, which comprised 20% and 23% of the total energy mix in 2012 and 2013 respectively.

#### Large Scale Wind Energy Acquired through Power Purchase Agreements

Through power purchase agreements, the Department has secured large scale wind farm output in a number of areas to provide a diversity of wind power resources. Such wind energy for the Department is being generated in wind farms located in the States of California, Oregon, Washington, Utah and Wyoming. Such power purchase agreements provide for an aggregate of 861 MWs of wind energy. Wind farms with output of
approximately 600 MWs are also subject to Department options to purchase such assets. Certain of these projects are described as follows:

**Milford Wind Corridor Phase I Project.** The Milford Wind Corridor Phase I Project (the “Milford I Project”) consists of SCPPA’s purchase of all energy generated by a 203.5 MW nameplate capacity wind farm comprised of 97 wind turbines located near Milford, Utah (the “Milford I Facility”), for a term of 20 years (unless earlier terminated) pursuant to a Power Purchase Agreement, by and between SCPPA and Milford Wind Corridor Phase I, LLC. Energy from the Milford I Facility is delivered to SCPPA over an approximately 90 mile, 345 kV transmission line extending from the wind generation site to the IPP Switchyard in Delta, Utah. SCPPA has issued revenue bonds in order to finance the purchase by prepayment of 6,764,301 MWh of energy from the Milford I Facility over the 20-year delivery term. The Department has entered into a power sales agreement with SCPPA that provides for the Department to pay for its 92.5% share of the Milford I Project on a “take-or-pay” basis as an operating expense of the Power System. See “OPERATING AND FINANCIAL INFORMATION – Take-or-Pay Obligations.”

**Milford Wind Corridor Phase II Project.** The Milford Wind Corridor Phase II Project (the “Milford II Project”) consists of SCPPA’s purchase of all energy generated by a 102 MW nameplate capacity wind farm comprised of 68 wind turbines located near Milford, Utah (the “Milford II Facility”), for a term of 20 years (unless earlier terminated) pursuant to a Power Purchase Agreement, by and between SCPPA and Milford Wind Corridor Phase II, LLC. Energy from the Milford II Facility is delivered to SCPPA over an approximately 88 mile, 345 kV transmission line extending from the wind generation site to the IPP Switchyard in Delta, Utah. SCPPA has issued revenue bonds in order to finance the purchase by prepayment of the energy from the Milford II Facility over the 20-year delivery term. In connection with the issuance of bonds relating to the Milford II Project, the Department has entered into a power sales agreement with SCPPA that provides for the Department to pay for its 95.098% share of the Milford II Project on a “take-or-pay” basis as an operating expense of the Power System. In addition, the Department has purchased the City of Glendale’s (“Glendale”) 4.902% output entitlement share of Milford II Project’s output. See “OPERATING AND FINANCIAL INFORMATION – Take-or-Pay Obligations.”

**Linden Wind Energy Project.** The Linden Wind Energy Project (the “Linden Project”) consists of SCPPA’s acquisition of a 50 MW nameplate capacity wind farm comprised of 25 wind turbines located near the town of Goldendale in Klickitat County, Washington. The Linden Project was developed and constructed by Northwest Wind Partners, LLC (“Northwest Wind”). SCPPA acquired the project from Northwest Wind pursuant to the terms of an asset purchase agreement between SCPPA and Northwest Wind. SCPPA has issued revenue bonds to finance the acquisition of the Linden Project. The Department has entered into a power sales agreement with SCPPA that provides for the Department to pay its 90.00% share of the Linden Project on a “take-or-pay” basis as an operating expense of the Power System. In addition, the Department has purchased Glendale’s 10.00% output entitlement share of Linden Project’s output, subject to Glendale’s right to repurchase all or a portion of such output at certain times and under certain circumstances. See “OPERATING AND FINANCIAL INFORMATION – Take-or-Pay Obligations.”

**Windy Point/Windy Flats Project.** The Windy Point/Windy Flats Project is a 262.2 MW nameplate capacity wind farm comprised of 114 wind turbines located in the Columbia Hills area of Klickitat County, Washington near the city of Goldendale (the “Windy Point Project”). The Windy Point Project is owned and operated by Windy Flats Partners, LLC (“Windy Flats”). Pursuant to a power purchase agreement with Windy Flats, SCPPA has agreed to purchase from Windy Flats all energy from the Windy Point Project for a delivery term of 20 years (unless earlier terminated). SCPPA has issued revenue bonds to finance the prepayment of the purchase of specified quantity of energy from the Windy
Point Project. The Department has entered into a power sales agreement with SCPPA that provides for the Department to pay its 92.37% share of the Windy Point Project on a “take-or-pay” basis as an operating expense of the Power System. In addition, the Department has purchased Glendale’s 7.63% output entitlement share of Windy Point Project’s output. See “OPERATING AND FINANCIAL INFORMATION – Take-or-Pay Obligations.”

Pine Tree Wind Project. The Pine Tree Wind Project is a wind generating facility north of Mojave, California, consisting of 90 wind turbines owned and operated by the Department. The Pine Tree Wind Project produces 135 MWs of capacity. However, available capacity will vary because wind in this area tends to blow in the afternoons and evenings and drops off during the daytime hours when the Power System load peaks. As part of normal operating procedures, the Department staff has notified Federal and State authorities concerning mortalities of golden eagles. Since June 2009, the Department staff has found nine golden eagle carcasses in the proximity of the Pine Tree Wind Project. The Department is working cooperatively and collaboratively with the U.S. Fish and Wildlife Service and the California Department of Fish and Game to investigate these deaths. The Department is also conducting advanced monitoring studies and surveys to determine potential causes of the eagle mortalities and mitigation options relating to the golden eagles. The Department is currently investigating the effectiveness of radar technology in detecting golden eagles and other birds of prey at the Pine Tree Wind Project. Golden eagles are a protected species, and the death or injury to a golden eagle in some circumstances can result in fines and penalties, including criminal sanctions. The Department is unable to predict the outcome of this investigation. However, to date there has been no adverse impact on the operations of the Pine Tree Wind Project.

Solar Power Programs. The Department currently has four programs to encourage the development of solar energy in Los Angeles: (i) the Solar Incentive Program in which residential and commercial customers are encouraged to install eligible solar photovoltaic systems with incentive funding provided by the Department; (ii) Department-built solar projects on City-owned properties; (iii) power purchase agreements for large-scale solar projects located outside the Los Angeles Basin built by solar developers; and (iv) a Feed-in-Tariff (“FiT”) Program, launched on February 1, 2013, has 5.4 MWs of solar photovoltaic generation installed within the Department’s service territory and connected to the Department’s electric distribution system.

Under the California Solar Initiative (“SB-1”) publicly owned electric utilities (“POUs”) are required to establish programs supporting the stated goal of the legislation to install 3,000 MWs of photovoltaic capacity in the State, and 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, starting at no less than $2.80 per watt, or the equivalent based on the energy produced by the solar energy system, measured in kilowatt-hours. Incentives are required to decrease at a minimum average rate of 7% per year. The Department’s incentive payment offerings currently range from $0.40 per watt for residential installations to $1.45 for government/non-profit installations. POUs also have to meet certain reporting requirements regarding installed capacity, number of installed systems, number of applicants and awarded incentives.

The Solar Photovoltaic Incentive Program includes using $313 million of ratepayer funds mandated by SB-1 to administer the program and subsidize customers for customer-owned solar projects that will offset their electricity use. As of February 2, 2015, the Department has committed $255 million in rebate payments to this program for 125 MWs of installations. The Department expects 254 MWs of customer owned net-metered solar by 2016 and an additional 49 MWs, for a total of 303 MWs, of customer owned net-metered solar by 2018.
The Department currently has 21 MWs of Department–built solar projects on City-owned properties. As one example, the Adelanto Solar Power Project is a 10 MW solar photovoltaic system, which is expected to deliver 515,700 MWhs of energy over the next 25 years, located at the existing Adelanto Switching and Converter Station near Adelanto, California.

In addition, the Pine Tree Solar Project was placed into commercial operation on March 15, 2013. The Pine Tree Solar Project is an 8.5 MW solar photovoltaic system expected to deliver 450,000 MWhs of energy over the next 25 years, located at the Department’s existing Pine Tree Wind Farm in the Tehachapi Mountains, California.

The Board and City Council have approved four power purchase agreements (“PPAs”) for the purchase of renewable energy from 620 MWs of solar photovoltaic projects. One PPA is a 25-year contract with K Road Moapa Solar, LLC which changed its name to Moapa Southern Paiute Solar, LLC for 250 MW, delivering up to 664,000 MWhs per year located on Moapa Band of Paiute Indians tribal land north of Las Vegas, Nevada. The second PPA is a 20-year contract through SCPPA for 210 MW of the Copper Mountain Solar 3 Project being developed by an affiliate of Sempra U.S. Gas and Power. Copper Mountain Solar 3 Project is near Boulder City, Nevada and is expected to deliver 515,000 MWhs of renewable energy a year to the Department. The third PPA is a 20-year contract for 60 MW of the RE Barren Ridge 1 Solar Project being developed by Recurrent Energy, an affiliate of Sharp, Inc. RE Barren Ridge 1 Solar Project is near the Mojave Desert in Kern County and is expected to deliver an annual average of 174,380 MWhs of renewable energy. The fourth PPA is a 25-year contract through SCPPA for 100 MW of the Springbok I Solar Farm Project being developed by 8minutenergy. Springbok I Solar Farm Project is near the Mojave Desert in Kern County and is expected to deliver an average of 264,684 MWhs of renewable energy a year to the Department.

In connection with the implementation of these PPAs, the Department is expected to upgrade certain transmission assets to accommodate these projects.

The Department is also exploring public private partnerships for large-scale solar projects in the Mojave Desert and other areas outside the Los Angeles Basin by 2020. This includes the 2,500-acre property purchased from Beacon Solar LLC in 2012, which is near the Pine Tree Wind Project (the “Beacon Property”). On the Beacon Property, the PPAs provide the Department with an option to purchase the solar projects after the developer exhausts the federal tax benefits. Five 25-year PPAs and associated agreements that have been executed for the development of five solar sites totaling 250 MWs within the Beacon Property, which are expected to produce up to 620,000 MWhs per year of solar energy by the end of 2016. As part of the PPAs for four of the five solar sites, the solar developers have agreed under separate agreements to develop up to 50 MWs of in-basin solar energy as part of the Department’s FiT Program.

The Department’s 150 MW FiT Program allows the Department to purchase, through a standard power purchase contract, electricity generated from participants’ renewable energy generating sources. Such sources will be located within the Department service territory and connected to the Power System. The energy purchased through the FiT Program is expected to count toward the Department’s RPS target. The FiT Program consists of two components: 100 MWs with a set pricing structure and 50 MWs with a competitive pricing structure. The 100 MW FiT set pricing program was launched on February 1, 2013. As discussed above, as part of the solar development on the Beacon Property, PPAs have been executed for up to 50 MW of in-basin solar energy. The FiT Program is expected to have all 150 MWs installed by 2016.

In addition to the current 150 MW FiT Program, the Department is developing an expanded FiT Program, which is expected to add another 300 MWs and bring the total FiT Program to 450 MWs.
**Geothermal Development.** The Department executed a power sales agreement with SCPPA for the Don A. Campbell Geothermal Energy Project (the “Don Campbell Project”), formerly the Wild Rose Geothermal Energy Project. The Don Campbell Project consists of SCPPA’s purchase of all energy generated by a 16.2 MW nameplate capacity binary geothermal power plant comprised of eight drilled commercial wells located in Mineral County, Nevada for an initial delivery term of 20 years starting December 31, 2013. The Department has entered into a power sales agreement with SCPPA that provides the Department a 84.62% share of the Don Campbell Project or 114 Gigawatt hours (GWhs) of energy annually.

In addition to the Don Campbell Project, the Department executed a power sales agreement with SCPPA for the Heber-1 Geothermal Project (the “Heber-1 Project”) in September 2013. The energy delivery commencement date is February 2, 2016 for an initial term of ten years, with an interim delivery period which may start as early as December 16, 2015. The Heber-1 Project is an existing geothermal complex which includes the Heber-1 double flash steam unit and the Gould 1 bottoming binary unit, located in Imperial County, California. The net energy generated from the Heber-1 Project is expected to be 46 MW. The Department’s share is 66.67% (30.68 MW) in the first three years and 78.0% (35.88 MW) for the remaining term. The equivalent average energy delivered to the Department is expected to be 285 GWhs annually.

**Imperial Valley Transmission Development.** The Department has entered into a Transmission Service Agreement with Imperial Irrigation District (“IID”) to acquire 100 MWs of transmission rights for a three-year term that is expected to begin in the summer of 2015. These transmission rights, along with other transmission rights and the use of the Cal ISO Grid, will allow future delivery of energy from geothermal and/or solar resources to Los Angeles.

**Renewable Energy Trust Fund and Energy Efficiency Trust Fund.** The Department established the Renewable Energy Trust Fund (the “Renewable Energy Trust Fund”) and the Energy Efficiency Trust Fund (the “Energy Efficiency Trust Fund”) to fund renewable energy sources and development, and energy efficiency programs including incentives and subsidies for commercial and residential solar power. Deposits to the Renewable Energy Trust Fund and the Energy Efficiency Trust Fund will be made at the direction of the Board.

**Green Power Program.** The Department offers its Green Power Program to all customers at a premium over standard rates. “Green Power” is produced from renewable resources such as wind energy and geothermal resources, rather than fossil-fueled or nuclear generating plants. This voluntary program includes customer-selected levels of Green Power purchases, subject to specified minimum requirements. Approximately 15,554 Department customers were subscribed to the Green Power Program as of January 2015. The Department is working on Green Power Program improvements that are intended to increase both the number of participants and the amount of green energy purchased through the program.

**Other Renewable Energy Project Developments.** The Department, on its own and through SCPPA, has received proposals from “green” power resources such as solar photovoltaic, wind, biomass, small hydro, solar thermal and geothermal power via solicitations. The Department is also considering opportunities related to utilization of land located in the Owens Valley area of the State for wind or geothermal and for improved transmission access to geothermal energy. Additional renewable energy resources will be obtained; however, the costs and schedules for implementation and feasibility of alternative energy projects may vary materially from initial projections. City Council approval may be required for the Department’s participation in or acquisition of renewable energy projects.
Energy Efficiency

The Charter authorizes the Department to engage in and finance activities related to the efficient use of energy and a number of State laws expressly require utilities such as the Department to collect and spend funds for these activities. The Department has a commitment to energy efficiency and continues to pursue cost-effective means of reducing or avoiding the need to generate electricity (particularly during peak periods). These activities defer the need to acquire costly new generating facilities, improve the value of electric service to customers and increase the Department’s overall load factor, thereby reducing or avoiding negative environmental impacts from power generation. Moreover, State laws enacted in 2005 and 2006 require POUs, such as the Department, 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 CEC describing their investment in energy efficiency and demand reduction programs. Assembly Bill 2021, which became a law in 2007, requires 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% by 2020. The Department is currently on track to meet or exceed these requirements and adopted a goal in August 2014 of achieving up to 15% energy savings by 2020.

The Department offers numerous programs and services for residential, commercial, industrial and institutional (“CII”) customers to encourage the installation and use of energy efficient measures and equipment such as:

- The Chiller Efficiency Program, which provides incentives for customers to replace old electric chillers with new, high-efficiency units to provide space conditioning for larger buildings, has reduced electrical demand since 2001 by more than 61 MWs;

- The Commercial Lighting Efficiency Offer (“CLEO”), which provides rebates for a wide variety of high efficiency lighting measures to retrofit existing buildings (CLEO has achieved over 500 GWhs of energy savings since 2000);

- The Small Business Direct Install (“SBDI”) Program, which assists certain small business customers (defined as those customers with a peak demand of 30 kW or below) in the City to become more energy efficient; qualifying customers receive a free energy and water assessment and free lighting retrofits, as well as select gas and water retrofits in partnership with the Southern California Gas Company; SBDI has achieved 170 GWhs of energy savings since its inception in 2008;

- The Energy Efficiency Technical Assistance Program for CII customers provides technical and engineering support to help industrial customers identify energy efficiency opportunities and develop qualifying projects that can then take advantage of existing incentive programs;

- The Home Energy Improvement Program, which continues and expands the Department’s formerly American Recovery and Reinvestment Act of 2009-funded Weatherization Program to serve primarily low-, moderate- and fixed-income residential customers in single- and multi-family housing with a broad spectrum of energy and water efficiency measures;

- Free pick-up and recycling of old, inefficient refrigerators in an environmentally sound manner and distribution of free, energy efficient refrigerators to nearly 80,000 low-income residential customers; this program has replaced and recycled more than 53,000 refrigerators since 2007, achieving an energy savings of 56 GWhs; and
The LED streetlight program that provided a $48 million loan to the City of Los Angeles to enable it to ultimately install over 180,000 highly energy efficient LED streetlights and reduce its consumption of electricity as a result. This program is now completed, and the loan has been repaid by the City. As a result, this model is being expanded as a $24 million loan to retrofit decorative street lighting with LED streetlights throughout the City.

From 2000 through 2014, the Department has spent approximately $500 million on its energy efficiency programs, and these programs have reduced long-term peak period demand and consumption by approximately 450 MWs and resulted in approximately 2,150 GWhs of energy savings. The Department anticipates spending approximately $100 million on energy efficiency programs for Fiscal Year 2014-15, with the budget increasing to approximately $145 million for Fiscal Year 2015-16. The Department anticipates increasing its expenditures for energy efficiency programs in future years, based on portfolio planning currently underway utilizing the results of the Department’s 2014 Energy Efficiency Potential Study. As a result of the Department’s 2014 Energy Efficiency Potential Study, the Board has adopted the goal of reducing usage by 15% by 2020 compared to 2010 levels. This is a significant increase from the 10% energy reduction target set by the State.

Fuel Supply for Department-Owned Generating Units and Apex Power Project

Natural gas (along with biogas) is used to fuel 100% of the Los Angeles Basin Stations. The Department’s fossil fuel requirements for the Los Angeles Basin Stations and the Apex Power Project for the electric load requirements of its customers in the City (referred to as “native load”) were 51.5 billion equivalent cubic feet of natural gas during Fiscal Year 2013-14. The Department determined that acquiring natural gas reserves is advantageous, reasonable and prudent to ensure stable, long-term natural gas supplies to help meet future power generation demands. In June 2005, the Department, the Turlock Irrigation District and SCPPA (acting on behalf of its member California cities of Anaheim, Burbank, Colton, Glendale and Pasadena) acquired rights in natural gas producing properties from the Anschutz Pinedale Corporation. Under the acquisition agreement, the Department obtained an approximately 74.5% ownership interest in a $300 million acquisition of producing gas leases of property in Sublette County, Wyoming. This acquisition provided approximately 13% of the Department’s average daily natural gas requirements for Fiscal Year 2013-14, and has saved the Department an imputed $37.0 million since 2005. No increase to this natural gas producing program is expected at this time, however further capital investment in such program will be reevaluated if market conditions change and the price of natural gas rises.

The Department obtains its remaining natural gas requirements through a competitively bid spot purchase program or through forward physical gas purchases for a specified period of time. The price of natural gas delivered into Southern California has fluctuated over the past few years and the Department expects prices to continue to fluctuate. To mitigate the effects of natural gas price volatility, the Department includes as part of the Electric Rates certain pass-through cost adjustments that provide recovery of natural gas and other fuel costs. See “ELECTRIC RATES – Rate Setting.” In addition, the City Council enacted an ordinance to authorize the Department to enter into financial hedge contracts with respect to natural gas purchases to stabilize fuel costs for native load. See “Note 9 – Derivative Instruments” in Appendix A (“Note 9”). Under this ordinance the Department’s General Manager also may enter into biogas supply agreements for a period not to exceed ten years, so long as certain conditions are met. The use of natural gas swaps, derivatives and other price hedging arrangements are subject to risk management policies and review procedures established by the Board. The Department has developed a natural gas procurement strategy that includes a program of entering into financial hedges with various counterparties that have permitted terms of up to ten years and are intended to mitigate customer exposure to gas price volatility. The policy permits up to 75% of the Department’s
natural gas requirements to be hedged through various measures (including such financial hedges), although the amount hedged in a given year may vary.

As of January 31, 2015, the Department has entered into financial natural gas hedges in various notional amounts per Fiscal Year for each Fiscal Year through Fiscal Year 2018 with an aggregate notional amount of approximately 12.1 million MMBtus. These hedges cover approximately 3% to 9% of the Department’s average daily natural gas requirements for the Fiscal Years through 2018. Tables describing the notional amount for each Fiscal Year and the durations of the hedges, as well as a discussion of the credit, basis and termination risks associated with such hedges, can be found in Note 9.

The Department has commenced a physical natural gas hedge program that is expected to eventually hedge up to 50% of its forecasted usage. Initial purchases of forward gas in the amount of 30,000 MMBtu per day for Fiscal Year 2015-16 were completed in late 2014 and early 2015.

The Department signed a fixed price, landfill gas contract in December 2011 (the “2011 Shell Contract”) with Shell Energy North America (“Shell”) for up to 10,000 MMBtus per day for 118 months beginning January 1, 2012. Energy produced from such gas is qualifying energy for RPS targets. Since production began, it has remained level at about 6,000 MMBtu per day. This purchase is expected to contribute up to 2.0% toward the Department’s RPS target. The CEC has certified the Los Angeles Basin Stations’ use of biogas from the 2011 Shell Contract. The certification is effective as of July 8, 2011 and will remain in effect unless certification is voluntarily withdrawn, any of the Los Angeles Basin Stations are permanently shut down or decommissioned, or the certification is revoked by the CEC because of noncompliance with the applicable RPS requirements. The CEC has issued a notice to comment on its proposed Renewables Portfolio Standard Eligibility Guidebook, 8th edition, which is used to qualify renewable resources under state legislative directives. The Department has provided a list of comments aimed at preserving the eligibility of its existing RPS resources.

In 2009, the Department and Shell entered into a contract for landfill biogas (the “2009 Shell Contract”). Also, in 2009, the Department and Atmos Energy Marketing, LLC (“Atmos”) entered into a contract for landfill biogas (the “2009 Atmos Contract”). Such contracts have expired, however, as noted in “FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – California Climate Change Policy Developments – California Renewable Electric Standard,” the CEC has denied certification for the use of biogas from the 2009 Shell Contract and the 2009 Atmos Contract as qualifying for the RPS target.

The Department has firm interstate natural gas transportation capacity on the Kern River Pipeline System for two different volumes at different rates, to 2016 and 2018, respectively. The total amount of capacity is sufficient to transport 80% of the average amount of natural gas needed for the Los Angeles Basin Stations under current Department forecasts. In Fiscal Year 2012-13, the capacity was 100% sufficient. Additional interstate pipeline capacity, if needed, is acquired through federally-approved capacity brokering programs or through gas purchases bundled with interstate transportation delivered into the Southern California Gas Company (“SoCalGas”) intrastate system.

Intrastate transportation and balancing services are provided to the Department by SoCalGas sufficient to meet 100% of the Los Angeles Basin Stations’ requirements under SoCalGas’s Basic Transportation Service program (“BTS”). This enables the Department to deliver Kern River Pipeline System gas to the BTS receipt points in the State.

Approximately 50% of the Department’s projected natural gas needs have been price hedged for Fiscal Year 2014-15 through financial hedges, physical gas supply contracts and gas reserves. This ratio declines gradually such that by Fiscal Year 2022-23, approximately 11% of projected natural gas needs
are hedged. The Department typically hedges a higher percentage of its natural gas needs as the operating year approaches, and is analyzing additional potential hedges for Fiscal Year 2015-16 and beyond. The Department has commenced the implementation of a physical natural gas hedge program, noted above, which will increase the percentage of hedge purchases through Fiscal Year 2022-23. Currently, the hedge percentage for Fiscal Year 2015-16 is 42%.

Water Supply for Department-Owned Generating Units

Water required for the operation of generating stations owned by the Department is secured from a number of sources. The Harbor Generating Station, Haynes Generating Station and Scattergood Generating Station use Pacific Ocean water for power plant cooling purposes. However, the Department is undertaking a long-term program of replacing the coastal generating units to eliminate the use of ocean water at these three locations in part to meet requirements of the State Water Resources Control Board limitations on the future use of once-through-cooling for these plants. See “See “THE POWER SYSTEM – Department Owned-Generating Units – Los Angeles Basin Stations – Once-Through-Cooling – State Water Resources Control Board” and “Regional Requirements – Thermal Discharges at Harbor Generating Station and Haynes Generating Station.” The Valley Generating Station, which is located inland, utilizes recycled water for cooling.

While the southwest United States is experiencing drought conditions, the water supplies for the Los Angeles Basin Stations are satisfactory for continued operations. Use of ocean water for cooling, transitions to closed cycle cooling, and use of reclaimed water alleviates the high demand for potable water. Nevertheless, due to low snow pack in the eastern Sierra Nevada Mountains, the hydroelectric power generation is forecasted to be lower than average in this geographical area. The Department estimates that production from Owens Gorge and Owens Valley Hydroelectric Generation and the Castaic Plant for Fiscal Years 2013-14 and 2014-15 was and will be 33% and 45% of normal production, respectively. The increase of the use of alternate resources such as renewables and natural gas is expected to reduce the impact of the southwest United States drought on the Power System.

Spot Purchases

The Department purchases capacity and energy from the Bonneville Power Administration and other Pacific Northwest utilities under short-term “spot” arrangements to be delivered over the Pacific DC Intertie. For further information on the Pacific DC Intertie, see “—Transmission and Distribution Facilities – Pacific DC Intertie and Sylmar Converter Station.” These purchases are used by the Department in conjunction with other resources for economical Power System operation. In addition, purchases of economical energy are made from other entities located in the Southwest.

The availability of economical energy on the spot market has fluctuated greatly in recent years. Historically the Department has not been dependent on such purchases to meet its customers’ requirements. Although the Department currently continues to find economical spot purchase opportunities (including some for renewable energy), it cannot predict the future availability of power from either the Pacific Northwest or the Southwest for purchases at prices below the Department’s costs for producing power from its own resources.

Cogeneration and Distributed Generation

Currently thermal cogeneration installed in the Department’s service area consists primarily of cogeneration projects of industrial and commercial customers. This totals approximately 252 MWs nameplate capacity. Some cogeneration projects sell excess energy to the Department under interconnection agreements.

Distributed generation (the generation of electricity at or near the point of use) within the Department’s service area currently consists primarily of cogeneration projects at customer facilities. Distributed generation also includes smaller generating units such as solar photovoltaic cells, fuel cells,
micro-turbines and other smaller combustion engines. The Department manages a new technology demonstration program to assess the viability of some of these technologies. The Department also supports the development of new technologies through customer incentive programs. See “—Renewable Power Initiatives” and “—Energy Efficiency.” These technology advancements may change the nature of energy generation and delivery and may materially affect the operating and financial position of the Department.

**Excess Capacity**

The Department uses its extensive transmission network to sell excess generating capacity into the California, Northwest and Southwest energy markets. Net income from those sales is used to reduce costs to the Department’s retail customers (with revenues primarily by being applied to the costs of capital improvements or towards an electric rate stabilization account). With equipment outages, retirement of equipment, anticipated load growth and changes in greenhouse gas regulations which impact emission allowances, the Department anticipates that revenue from excess energy sales will be less certain than in the past. Wholesale revenues, as shown in “SELECTED FINANCIAL INFORMATION” under “OPERATING AND FINANCIAL INFORMATION – Financial Information,” have accounted for less than 2% of overall Power System revenues in recent years.

**Transmission and Distribution Facilities**

Electricity from the Department’s power generation sources is delivered to customers over a complex transmission and distribution system. To deliver energy from generating plants to customers, the Department owns and/or operates approximately 19,840 miles of alternating current (“AC”) and direct current (“DC”) transmission and distribution circuits operating at voltages ranging from 120 volts to 500 kilovolts (“kV”). In addition to using its transmission system to deliver electricity from its power generation resources, the Department transmits energy for others through such system when surplus transmission capacity is available and such transmission is permitted by the Master Resolution. As the operating agent of the Pacific DC Intertie, the Southern Transmission System, the Mead-Adelanto Transmission Project and certain Navajo-McCullough transmission facilities (all such facilities being described below), the Department transmits energy for the co-owners of or participants in these facilities.

Pursuant to Assembly Bill 1890, signed into law on January 1, 1997, as part of the deregulation of the State electric industry, municipal utilities such as the Department, were encouraged, but not required, to transfer operational control of their electric transmission facilities to the Cal ISO. The Department owns and operates in excess of 25% of the transmission facilities in the State. While the Department has not transferred operational control of its transmission facilities to the Cal ISO, the Department interacts with the Cal ISO on a regular basis. The Department serves as the scheduling coordinator for the delivery of that portion of the Department’s energy that requires use of any part of the Cal ISO Grid. The Department also coordinates with the Cal ISO with respect to some lines that are jointly owned by the Department and others. The Department is responsible for the costs associated with its use of the Cal ISO Grid. The Department is registered as a participant in wholesale transactions on the Cal ISO market. In the future, the Department may have more interaction with the Cal ISO in order to transport renewable power and to take advantage of trading opportunities.

Legislation considered from time to time by the U.S. Congress and the State could potentially increase the level of jurisdictional control over the generation, transmission and distribution assets that comprise the Department’s Power System and could encourage voluntary participation by the Department in a regional transmission organization. The City opposes any participation in a regional transmission organization that would be mandatory. The Department monitors any potential restrictions regarding control of transmission rates, authority to finance the Power System using bonds and use of the Power System to deliver electric power to the City.

Certain transmission facilities available to the Department are discussed below.
Southern Transmission System. The Southern Transmission System (the “STS”) is an approximately 490-mile, ±500 kV DC transmission line from the Intermountain Power Generating Station, near Delta, Utah, to Adelanto, California, together with an AC/DC converter station at each end of the line. The STS is owned by IPA and is one of three major components of the IPP. The Department entered into a transmission service contract with SCPPA for a 59.5% entitlement in SCPPA’s share of the transfer capability of the STS to provide for the transmission of energy from the IPP Converter Station to the Adelanto Converter Station until 2027. After the completion of an upgrade in December 2010 to its capacity, a maximum of 2,400 MWs can be transmitted over the STS. The Department’s entitlement in SCPPA’s share of the transfer capability of the STS is now approximately 1,428 MWs.

Northern Transmission System. The Northern Transmission System (the “NTS”) includes two approximately 50-mile, 345 kV transmission lines from IPP to the Mona Substation in Northern Utah, and one approximately 144-mile, 230 kV transmission line from IPP to the Gonder Substation in Nevada. The NTS was constructed for the delivery of power from IPP to certain municipalities in Utah and certain cooperative purchasers. Capacity on the NTS is available to the Department through the IPP Excess Power Sales Agreement. The Department can have up to a maximum NTS share allocation of 43.141% of the total capacity depending on the generation deemed excess by the 29 Utah municipalities and cooperatives that have access to such power. The capacity from IPP to Mona is 1,400 MW; the capacity from Mona to IPP is 1,200 MW; the capacity from IPP to Gonder is 200 MW; and the capacity from Gonder to IPP is 117 MW.

Pacific DC Intertie and Sylmar Converter Station. The Pacific DC Intertie is an approximately 846-mile, ±500 kV DC transmission system that connects Southern California to the hydroelectric and wind generation resources of the Pacific Northwest. A maximum of 3,100 MWs can be transmitted over the entire Pacific DC Intertie System. The Department owns a 40% interest in the southern portion of the Pacific DC Intertie from the Nevada-Oregon border to its southern terminus at the Sylmar Converter Station in Sylmar, California and is the operating agent of the southern portion of the Pacific DC Intertie. The northern portion of the Pacific DC Intertie is owned and operated by Bonneville Power Administration (“BPA”) and extends from the Nevada-Oregon border to BPA’s Celilo Station in The Dalles, Oregon.

Devers-Palo Verde No. 1 Transmission Line. The Devers-Palo Verde No. 1 Transmission Line is an approximately 250-mile, 500 kV AC line owned by Edison that connects the PVNGS with the Devers Substation outside Desert Hot Springs, California. As part of an exchange agreement, the Department purchases up to 368 MWs of bi-directional firm transmission service on the Devers-Palo Verde No. 1 Transmission Line from Edison (the “Devers-Palo Verde Agreement”) at the rate being charged by the Cal ISO for that same service. In the winter of 2013, Edison completed construction of a new Colorado River Substation near Blythe, California and has looped the Devers-Palo Verde No. 1 Transmission Line into this substation. The Devers-Palo Verde transmission path now consists of the Devers-Colorado River and Colorado River-Palo Verde transmission lines. The Department has the right to terminate the service upon 12 months written notice.

Mead-Phoenix Transmission Project. The Mead-Phoenix Transmission project is an approximately 256-mile, 500 kV AC transmission line which originates at the Westwing substation in Phoenix, Arizona, connects with the Mead substation near Boulder City, Nevada and terminates at the Marketplace substation nearby. The Mead-Phoenix Transmission Project is owned by SCPPA, APS, M-S-R Public Power Agency, Salt River Project, Western and Startrans IO, L.L.C. The Department has entered into a transmission service contract with SCPPA that obligates the Department until 2030 to pay for its share of the Mead-Phoenix Transmission Project on a “take-or-pay” basis as an operating expense of the Power System. The Department’s share is 31.0924% of SCPPA’s share of the Westwing-Mead component of the Mead-Phoenix Transmission Project and 17.8313% of SCPPA’s share of the Mead-Marketplace component of the Mead-Phoenix Transmission Project. The Department’s average share of the Mead-Phoenix Transmission Project components is 24.75% of SCPPA’s share of the Mead-Phoenix
Transmission Project. Payments associated with the Mead-Phoenix Transmission Project include fixed operating costs and debt service on bonds issued by SCPPA for the Mead-Phoenix Transmission project. See “OPERATING AND FINANCIAL INFORMATION – Take-or-Pay Obligations.”

**Mead-Adelanto Transmission Project.** The Mead-Adelanto Transmission Project is an approximately 202-mile, 500 kV AC transmission line between the Adelanto substation, near Victorville, California and the Marketplace substation, near Boulder City, Nevada. The Mead-Adelanto Transmission Project was constructed by its owners, SCPPA, M-S-R Public Power Agency, Western and Startrans IO, L.L.C., in connection with the Mead-Phoenix Transmission Project. The Department has entered into a transmission service contract with SCPPA that obligates the Department until 2030 to pay for its share of the Mead-Adelanto Transmission Project on a “take-or-pay” basis as an operating expense of the Power System. The Department’s share is 35.7% of SCPPA’s share of the Mead-Adelanto Transmission Project. Payments associated with the Mead-Adelanto Transmission Project include fixed operating costs and debt service on bonds issued by SCPPA for the project. See “OPERATING AND FINANCIAL INFORMATION – Take-or-Pay Obligations.”

**Navajo-McCullough Transmission Line.** The Navajo-McCullough Transmission Line is a 274-mile, 500 kV AC transmission line that originates at the Navajo Generating Station near Page, Arizona, connects through the Crystal Substation near Las Vegas, Nevada and terminates at the McCullough substation, near Boulder City, Nevada. The Department owns 48.9% of the Navajo-McCullough Transmission Line, which was constructed as a part of the Navajo Generating Station. The Crystal Substation was constructed by NV Energy. NV Energy owns 100% of the Crystal Substation on behalf and for the benefit of the Navajo Generating Station, including the Department.

**Eldorado Transmission System.** The Eldorado Transmission System’s major components are the 59-mile, 500 kV AC Mohave-Eldorado transmission line, the 500 kV Mohave Switchyard, the Eldorado substation, which is comprised of a 220 kV switchyard and a 500 kV switchyard, and two parallel 15-mile 220 kV AC Eldorado-Mead transmission lines. Pursuant to a System Conveyance and Co-Tenancy Agreement, the Department is a 30.4% co-owner of the Mohave-Eldorado transmission line, 20% co-owner of the Mohave Switchyard and 21% co-owner of the 500 kV switchyard that is part of the Eldorado substation, which are assets associated with the Eldorado Transmission System.

**Barren Ridge Renewable Transmission Project (“BRRTP”).** The Department’s BRRTP involves expansion of the Barren Ridge Switching Station, construction of a new switching station in Haskell Canyon (the “Haskell Switching Station”), constructing a new 61-mile double circuit 230 kV transmission line between these two stations, installing a new 230 kV circuit between Haskell Switching Station and the existing Castaic Power Plant, and the re-conductoring of the existing 230 kV transmission line from Barren Ridge Switching Station to the Rinaldi Substation in the San Fernando Valley. This project will increase the transmission capacity of renewable energy flowing into the Los Angeles Basin from generating facilities in Owens Valley and the Tehachapi Mountains by 2,000 MWs. This project required both an environmental impact statement and environmental impact report in compliance with state and federal requirements. The environmental impact report, required under State and federal law, was approved by the Board in September 2012. Construction has commenced and is expected to be completed by the summer of 2017. The completion date will not impact expected commercial operation dates for renewable projects that are expecting to interconnect to the BRRTP.

**Projected Capital Improvements**

The Department has developed a series of Power System integrated resource plans with each plan updating and refining the previous plan. The plans are developed in conjunction with the Department’s strategic planning to meet its goals of continuing to provide reliable service to customers, maintaining a competitive price for the Power System’s services and providing environmental leadership. Such resource plans act as guidance for the Department in implementing more specific short-term and long-
term financial plans. The Power System’s most current integrated resource plan was released in December 2014.

Based on the Department’s April 2014 Retail Electric Sales and Demand Forecast, the Department anticipated that gross customer electricity consumption would increase from Fiscal Year 2012-13 to Fiscal Year 2022-23 at a forecasted rate of approximately 1.2% per year without consideration of the Department’s measures to promote energy efficiency and distributed generation. That load growth rate reflects, in the later part of the ten year planning period, increases due in part to fuel switching in the transportation sector including the increase of plug-in hybrid electric vehicles. In the Power System’s most recent integrated resource plan significant energy efficiency measures are planned for as a cost effective resource, along with support for customer solar projects. This, together with the Board’s adoption in August 2014 of a plan to achieve 15% energy efficiency savings by 2020 are anticipated to result in net overall energy consumption that decreases by 0.17% per year over this period. Enhancement and expansion of electric transmission resources will enable access to renewable energy resources. Continued modernization of the Department’s Castaic Plant and the repowering of in-basin gas-fired generation with more flexible “quick start units” will assist in integrating intermittent renewable resources into the Power System. Capital investments in the transmission and distribution system, including new business service and electric feeder lines, are required to support future growth. New control and monitoring systems are needed to continue to provide reliable and secure system operations. See “—Power System Reliability Program” below.

Castaic Power Plant Modernization. The seven units of the Castaic Plant are currently being rotated out of service for modernization in a multi-phase process expected to be completed in 2017. The scope of work includes upgrades to the hydroelectric plant and replacement of turbines, installation of plant automation, installation of generator exciters for all seven units and improvements to the plant relay protection system. This refurbishment is projected to increase efficiency and add up to 80 MWs of capacity. See “—Department-Owned Generating Units — Los Angeles Basin Stations” and “—Castaic Pump Storage Power Plant.”

Power System Reliability Program. A significant power outage in 2006 caused the Department to conduct an evaluation of its electrical infrastructure. These events led to the development of a comprehensive, long-term power reliability program (the “Power Reliability Program”) with the following major components: (a) mitigation of problem circuits and stations based on the types of outages specific to the facility, including among other things, timely, permanent repairs of distribution circuits after a failure and fixing poorly performing circuits, (b) proactive maintenance and capital improvements that take into account system load growth and the inspections and routine maintenance that must take place to identify problems before they occur and (c) replacement cycles for facilities that are in alignment with the equipment’s life cycle, including replacement of overloaded transformers, as well as replacing aging underground cables, overhead poles and circuits and substation equipment. The Power Reliability Program was renamed the Power System Reliability Program (the “Power System Reliability Program”), in the spring of 2014. The Power System Reliability Program expanded the scope of the Power Reliability Program, in order to assess all Power System assets affecting reliability in an integrated and comprehensive manner and propose corrective actions as well as capital expenditures designed to minimize future outages and maintain reliability in the short and long term. The Power System Reliability Program includes the establishment of metrics and indices to help prioritize infrastructure replacement and expenditures from all major functions of the Power System, including distribution, transmission, generation, and substations. The Power System Reliability Program is anticipated to be updated on an annual basis to adjust to varying Power System conditions and resource allocations.
Projected Capital Expenditures. As indicated in the table below, for Fiscal Year 2014-15 through Fiscal Year 2018-19, the Department expects to invest approximately $8.6 billion in capital improvements to the Power System.

EXPECTED CAPITAL IMPROVEMENTS TO THE POWER SYSTEM
FIVE-YEAR PERIOD BEGINNING JULY 1, 2014
(in Millions)

<table>
<thead>
<tr>
<th>Infrastructure</th>
<th>5-Year Totals</th>
</tr>
</thead>
<tbody>
<tr>
<td>Various Generation Station Improvements</td>
<td>$2,489</td>
</tr>
<tr>
<td>Power System Reliability Program</td>
<td>2,905</td>
</tr>
<tr>
<td>Renewable Portfolio Standard (RPS):</td>
<td></td>
</tr>
<tr>
<td>Pine Tree Wind Project,</td>
<td></td>
</tr>
<tr>
<td>Renewable Energy Project Development</td>
<td></td>
</tr>
<tr>
<td>Renewable Transmission Projects</td>
<td>1,890</td>
</tr>
<tr>
<td>Power Integrated Resource Plan:</td>
<td></td>
</tr>
<tr>
<td>Haynes and Scattergood</td>
<td></td>
</tr>
<tr>
<td>Repowering and Castaic Modernization</td>
<td>817</td>
</tr>
<tr>
<td>Integrated Support and Other Joint Services: IT, Facilities, Customer Services, Fleet</td>
<td>458</td>
</tr>
<tr>
<td>Total Power System Capital Improvements</td>
<td>$8,559</td>
</tr>
</tbody>
</table>

Source: Department of Water and Power of the City of Los Angeles.
Note: Total may not equal sum of parts due to rounding.

The table below indicates, for Fiscal Year 2014-15 through Fiscal Year 2018-19, the expected funding sources for the capital improvements to the Power System expected for such Fiscal Years.

EXPECTED FUNDING SOURCES FOR CAPITAL IMPROVEMENTS TO THE POWER SYSTEM
(in Millions)

<table>
<thead>
<tr>
<th>Fiscal Year Ending (June 30)</th>
<th>Internally Generated Funds</th>
<th>External/Debt Financing</th>
<th>Total Capital Expenditures⁽¹⁾</th>
</tr>
</thead>
<tbody>
<tr>
<td>2015</td>
<td>$797</td>
<td>$679⁽²⁾</td>
<td>$1,476</td>
</tr>
<tr>
<td>2016</td>
<td>639</td>
<td>1,141</td>
<td>1,780</td>
</tr>
<tr>
<td>2017</td>
<td>597</td>
<td>1,043</td>
<td>1,640</td>
</tr>
<tr>
<td>2018</td>
<td>604</td>
<td>1,220</td>
<td>1,824</td>
</tr>
<tr>
<td>2019</td>
<td>783</td>
<td>1,056</td>
<td>1,839</td>
</tr>
<tr>
<td></td>
<td>$3,420</td>
<td>$5,139</td>
<td>$8,559</td>
</tr>
</tbody>
</table>

Source: Department of Water and Power of the City of Los Angeles.
⁽¹⁾ Net of reimbursements to the Department.
⁽²⁾ Consists of proceeds of the Department’s Power System Revenue Bonds, 2014 Series D and Power System Revenue Bonds, 2014 Series E, which have already been issued.

The Board is expected to act upon a capital budget for the Power System for Fiscal Year 2015-16 through Fiscal Year 2019-20 at a Board meeting in March 2015. Department staff is expected to recommend a reduction in external/debt financing and total capital expenditures (approximately 10%) as compared to the information provided above. No assurance can be given as to how the Board will act with respect to any proposed capital budget.
The particular programs and commitments for capital improvements to the Power System are subject to review by Department stakeholders and others. The estimated costs of, and the projected schedule for, the expected capital improvements to the Power System and the Department’s other capital projects are subject to a number of uncertainties. The ability of the Department to complete such capital improvements may be adversely affected by various factors including: (i) estimating errors, (ii) design and engineering errors, (iii) changes to the scope of the projects, (iv) delays in contract awards, (v) material and/or labor shortages, (vi) unforeseen site conditions, (vii) adverse weather conditions, (viii) contractor defaults, (ix) labor disputes, (x) unanticipated levels of inflation, (xi) environmental issues, (xii) the ability to access the capital markets at a particular time and (xiii) delays in approvals of rate increases. No assurance can be made that the proposed projects will not cost more than the current budget for these projects. Any schedule delays or cost increases could result in the need to issue additional obligations and may result in increased costs to the Department. All payments of project costs associated with projected capital improvements are subject to Board approval.

Seismic Activity

The City and the Owens River and Mono Basin areas are located in regions of seismic activity. The principal earthquake fault in the Los Angeles area is the San Andreas Fault, which extends an estimated 700 miles from north of the San Francisco area to the Salton Sea. At its nearest point to the City, the San Andreas Fault is about 35 miles north of the Los Angeles Civic Center.

In April 2008, the Uniform California Earthquake Rupture Forecast (the “Earthquake Forecast”) was issued by the Working Group on California Earthquake Probabilities. Organizations sponsoring the Working Group on California Earthquake Probabilities include the U.S. Geological Survey, the California Geological Survey and the Southern California Earthquake Center. According to the Earthquake Forecast, the probability of a magnitude 6.7 or larger earthquake over the next 25 years striking the greater Los Angeles area is 67%. For the entire California region, the fault with the highest probability of generating at least one magnitude 6.7 quake or larger is the San Andreas Fault (59% in the next 25 years). Earthquake probabilities for many parts of the State are similar to those in previous studies, but the new probabilities calculated for the Elsinore and San Jacinto Faults in southern California are about half those previously determined. For the far northwestern part of the State, a major source of earthquakes is the offshore 750-mile-long Cascadia Subduction Zone, the southern part of which extends about 150 miles into the State. For the next 25 years there is a 10% probability of a magnitude 8 to 9 quake somewhere along that zone. There are hundreds of other faults throughout Southern California that could also cause damaging earthquakes.

While it is impossible to accurately predict the cost or effect of a major earthquake on the Power System or to predict the effect of such an earthquake on the Department’s ability to provide continued uninterrupted service to all parts of the Department’s service area, there have been various studies conducted to assist the Department in assessing seismic risks. Based on these studies, the Department completed numerous projects designed to mitigate seismic risks and seismically strengthen Power System infrastructure and facilities. Projects include landslide repairs and bank replacements, the placement of spare transformers and the installation of generating peaking units at the Valley Generating Station and Haynes Generating Station to provide peaking capacity and the ability for generating units to go from a shutdown condition to an operating condition and start delivering power without assistance from the power grid. No studies have been conducted or commissioned by the Department outside of the State. See “THE DEPARTMENT – Insurance.”
The Department’s service area consists of the City, where over 1.4 million customers are served, and certain areas of Inyo and Mono Counties in the State, where approximately 4,483 customers are served. As of December 31, 2014, 30% of the Power System’s total energy sales (measured in MWhs) were to residential customers, 60% to commercial and industrial customers and the remaining 10% to all other purchasers. Revenues from residential and commercial/industrial customers were approximately 32% and 65% of total revenue, respectively.

Summary of Operations

The table below provides certain operating information with respect to the Power System.

### POWER SYSTEM
### SELECTED OPERATING INFORMATION
### (Unaudited)

<table>
<thead>
<tr>
<th>Operating Statistics</th>
<th>Six Month Period Ended December 31</th>
<th>Fiscal Year Ended June 30</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net Energy Load (1)</td>
<td>14,368</td>
<td>13,797</td>
</tr>
<tr>
<td>Net Hourly Peak Demand (MWs)</td>
<td>6,396</td>
<td>5,862</td>
</tr>
<tr>
<td>Annual Load Factor (%)</td>
<td>50.86</td>
<td>53.28</td>
</tr>
<tr>
<td>Electric Energy Generation, Purchases and Interchanges (1)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Generation (2)(3)</td>
<td>8,778</td>
<td>7,131</td>
</tr>
<tr>
<td>Purchases (3)</td>
<td>5,705</td>
<td>6,420</td>
</tr>
<tr>
<td>Miscellaneous Energy Receipts</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td>Total Energy (1)</td>
<td>14,483</td>
<td>13,551</td>
</tr>
<tr>
<td>Less:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Miscellaneous Energy Deliveries (1)(4)</td>
<td>90</td>
<td>85</td>
</tr>
<tr>
<td>Losses and System Uses (1)</td>
<td>907</td>
<td>456</td>
</tr>
<tr>
<td>On-System Sales (1)</td>
<td>13,486</td>
<td>13,101</td>
</tr>
<tr>
<td>Sales of Energy (1)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Residential</td>
<td>4,110</td>
<td>4,104</td>
</tr>
<tr>
<td>Commercial and Industrial</td>
<td>8,322</td>
<td>8,087</td>
</tr>
<tr>
<td>Total</td>
<td>1,494</td>
<td>933</td>
</tr>
<tr>
<td>Total</td>
<td>13,926</td>
<td>13,124</td>
</tr>
<tr>
<td>Number of Customers – (Average, in thousands): (5)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Residential</td>
<td>1,359</td>
<td>1,354</td>
</tr>
<tr>
<td>Commercial and Industrial</td>
<td>123</td>
<td>122</td>
</tr>
<tr>
<td>Total</td>
<td>7</td>
<td>7</td>
</tr>
</tbody>
</table>

Source: Department of Water and Power of the City of Los Angeles.

(1) Thousands of MWhs.
(2) Does not include energy generated at Hoover Power Plant for plant use and for the use of the Bureau of Reclamation and the cities of Boulder City, Nevada; Burbank, California; Glendale, California and Pasadena, California.
(3) Purchases from SCPPA are classified as Generation for quarterly results and Purchases for Fiscal Year end results.
(4) Deliveries include BPA AC/DC returns, Pasadena, California, APS, Edison and SCPPA losses, the Navajo Generating Station and Mohave Generating Station start-up and Edison Base Service Pump.
(5) Customer class definitions were updated in Fiscal Year 2013-14, and prior year averages have been restated to conform to the new customer class definitions.
## Financial Information

The tables below provide certain financial information with respect to the Power System.

### POWER SYSTEM

#### SELECTED FINANCIAL INFORMATION

(Dollars in Thousands)  
(Unaudited)

<table>
<thead>
<tr>
<th></th>
<th>Six Month Period Ended</th>
<th>Fiscal Year Ended June 30&lt;sup&gt;(1)&lt;/sup&gt;</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>December 31</td>
<td>2014</td>
</tr>
<tr>
<td>Operating Revenues</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Residential</td>
<td>$610,469</td>
<td>$1,042,641</td>
</tr>
<tr>
<td>Commercial and Industrial</td>
<td>1,217,057</td>
<td>2,232,878</td>
</tr>
<tr>
<td>Sales for resale&lt;sup&gt;(2)&lt;/sup&gt;</td>
<td>55,980</td>
<td>42,809</td>
</tr>
<tr>
<td>Other&lt;sup&gt;(3)&lt;/sup&gt;</td>
<td>(2,396)</td>
<td>1,492</td>
</tr>
<tr>
<td><strong>Total Operating Revenues</strong></td>
<td><strong>$1,881,110</strong></td>
<td><strong>$3,319,820</strong></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th>Average Revenue per KWh Sold&lt;sup&gt;(4)&lt;/sup&gt;</th>
<th>2014</th>
<th>2013</th>
<th>2012</th>
<th>2011</th>
<th>2010</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential</td>
<td>0.149</td>
<td>0.133</td>
<td>0.135</td>
<td>0.134</td>
<td>0.134</td>
<td>0.136</td>
</tr>
<tr>
<td>Commercial and Industrial</td>
<td>0.142</td>
<td>0.142</td>
<td>0.131</td>
<td>0.132</td>
<td>0.132</td>
<td>0.133</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>3</td>
<td>6</td>
<td>6</td>
<td>6</td>
<td>6</td>
<td>6</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th>Operating income</th>
<th>2014</th>
<th>2013</th>
<th>2012</th>
<th>2011</th>
<th>2010</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>$358,739</td>
<td>$489,437</td>
<td>$477,768</td>
<td>$452,139</td>
<td>$430,832</td>
<td>$609,893</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th>As % of revenues</th>
<th>2014</th>
<th>2013</th>
<th>2012</th>
<th>2011</th>
<th>2010</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>19.1%</td>
<td>14.7%</td>
<td>15.1%</td>
<td>14.7%</td>
<td>13.8%</td>
<td>18.9%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th>Change in Fund Net Position&lt;sup&gt;(6)&lt;/sup&gt;</th>
<th>2014</th>
<th>2013</th>
<th>2012</th>
<th>2011</th>
<th>2010</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>$296,603</td>
<td>$387,500</td>
<td>$383,017</td>
<td>$368,263</td>
<td>$316,456</td>
<td>$542,075</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th>Change in Fund Net Position&lt;sup&gt;(7)&lt;/sup&gt;</th>
<th>2014</th>
<th>2013</th>
<th>2012</th>
<th>2011</th>
<th>2010</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>$31,017</td>
<td>$134,500</td>
<td>$136,483</td>
<td>$118,186</td>
<td>$57,641</td>
<td>$321,600</td>
</tr>
</tbody>
</table>

---

Source: Department of Water and Power of the City of Los Angeles.  
<sup>(1)</sup> Derived from the Power System Financial Statements.  
<sup>(2)</sup> Includes sales of power and transmission services to other utilities.  
<sup>(3)</sup> Net of Uncollectible Accounts.  
<sup>(4)</sup> The calculated Average Revenue per KWh Sold is based on dividing reported Operating Revenues by customer class by volumes for that customer class, including deferred revenues. The actual customer rates may differ from these calculated figures due to a variety of factors, including (1) demand and energy charges for commercial rates, (2) changes in usage between rate tiers within a customer class and between years, and (3) other factors including customer classification issues.  
<sup>(5)</sup> MWh use per residential customer, with figures for the six month partial periods pro-rated accordingly.  
<sup>(6)</sup> Before Power Transfer.  
<sup>(7)</sup> After Power Transfer.

[Remainder of page intentionally left blank]
### POWER SYSTEM

#### SUMMARY OF REVENUES, EXPENSES AND DEBT SERVICE COVERAGE

(Dollars in Thousands)

(UNAUDITED)

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Dec 31</td>
<td></td>
<td>Fiscal Year Ended June 30(1)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Operating Revenues</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sales of Electric Energy:</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Residential</td>
<td>$ 610,469</td>
<td>$ 564,472</td>
<td>$1,042,641</td>
<td>$ 1,019,656</td>
<td>$ 976,820</td>
<td>$ 966,436</td>
<td>$1,014,610</td>
</tr>
<tr>
<td>Commercial and industrial</td>
<td>1,217,057</td>
<td>1,105,188</td>
<td>2,232,878</td>
<td>2,061,637</td>
<td>2,039,522</td>
<td>2,046,850</td>
<td>2,062,415</td>
</tr>
<tr>
<td>Sales for resale</td>
<td>55,980</td>
<td>39,251</td>
<td>42,809</td>
<td>67,764</td>
<td>36,136</td>
<td>84,262</td>
<td>126,354</td>
</tr>
<tr>
<td>Other(2)</td>
<td>(2,396)</td>
<td>10,167</td>
<td>1,492</td>
<td>13,445</td>
<td>29,202</td>
<td>28,409</td>
<td>31,814</td>
</tr>
<tr>
<td><strong>Total Operating Revenues</strong></td>
<td>$1,881,110</td>
<td>$1,719,078</td>
<td>$3,319,820</td>
<td>$3,162,502</td>
<td>$3,081,680</td>
<td>$3,125,957</td>
<td>$3,235,193</td>
</tr>
<tr>
<td><strong>Operating Expenses</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Production:</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fuel for Generation</td>
<td>$ 231,915</td>
<td>$ 212,332</td>
<td>$436,643</td>
<td>$ 446,450</td>
<td>$ 403,406</td>
<td>$ 435,812</td>
<td>$ 480,707</td>
</tr>
<tr>
<td>Purchased Power</td>
<td>534,765</td>
<td>495,397</td>
<td>977,187</td>
<td>895,092</td>
<td>909,910</td>
<td>853,745</td>
<td>829,177</td>
</tr>
<tr>
<td>Energy Cost</td>
<td>$ 766,680</td>
<td>$ 707,729</td>
<td>$1,413,830</td>
<td>$1,341,542</td>
<td>$1,313,316</td>
<td>$1,289,557</td>
<td>$1,309,884</td>
</tr>
<tr>
<td>Maintenance and Other Operating Expenses</td>
<td>511,853</td>
<td>462,777</td>
<td>950,027</td>
<td>924,707</td>
<td>922,206</td>
<td>1,018,631</td>
<td>977,550</td>
</tr>
<tr>
<td><strong>Total Operating Expenses</strong>(3)</td>
<td>$1,278,533</td>
<td>$1,170,506</td>
<td>$2,363,857</td>
<td>$2,266,249</td>
<td>$2,235,522</td>
<td>$2,308,188</td>
<td>$2,287,434</td>
</tr>
<tr>
<td>Income from Operations**(3)</td>
<td>$ 602,577</td>
<td>$ 548,572</td>
<td>$ 955,963</td>
<td>$ 896,253</td>
<td>$ 846,158</td>
<td>$ 817,769</td>
<td>$ 947,759</td>
</tr>
<tr>
<td>Allowance for funds used during construction</td>
<td>17,082</td>
<td>9,212</td>
<td>18,636</td>
<td>33,672</td>
<td>32,187</td>
<td>11,806</td>
<td>7,665</td>
</tr>
<tr>
<td>Other nonoperating income and expenses, net</td>
<td>40,482</td>
<td>53,816</td>
<td>112,036</td>
<td>99,552</td>
<td>127,081</td>
<td>122,732</td>
<td>131,434</td>
</tr>
<tr>
<td>Contributions in aid of construction</td>
<td>26,322</td>
<td>15,150</td>
<td>45,239</td>
<td>46,860</td>
<td>26,731</td>
<td>27,983</td>
<td>13,069</td>
</tr>
<tr>
<td><strong>Change in Fund Net Position</strong>(4)</td>
<td>$ 686,463</td>
<td>$ 626,750</td>
<td>$1,131,874</td>
<td>$1,076,337</td>
<td>$1,032,157</td>
<td>$ 980,290</td>
<td>$1,099,927</td>
</tr>
<tr>
<td><strong>Debt Service</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Interest</td>
<td>168,321</td>
<td>158,954</td>
<td>318,871</td>
<td>297,576</td>
<td>280,935</td>
<td>277,026</td>
<td>207,700</td>
</tr>
<tr>
<td>Principal</td>
<td>110,705</td>
<td>132,361</td>
<td>132,382</td>
<td>129,249</td>
<td>62,158</td>
<td>123,820</td>
<td>101,649</td>
</tr>
<tr>
<td><strong>Total debt service</strong></td>
<td>$ 279,026</td>
<td>$ 291,315</td>
<td>$ 451,253</td>
<td>$ 426,825</td>
<td>$ 343,093</td>
<td>$ 400,846</td>
<td>$ 309,349</td>
</tr>
<tr>
<td><strong>Debt Service Coverage Ratio</strong></td>
<td>2.46</td>
<td>2.15</td>
<td>2.51</td>
<td>2.52</td>
<td>3.01</td>
<td>2.45</td>
<td>3.56</td>
</tr>
<tr>
<td>Depreciation, amortization and accretion</td>
<td>$ 243,838</td>
<td>$ 230,495</td>
<td>$ 466,526</td>
<td>$ 418,485</td>
<td>$ 394,019</td>
<td>$ 386,937</td>
<td>$ 337,866</td>
</tr>
<tr>
<td>Transfers to the Reserve Fund of the City</td>
<td>$ 265,586</td>
<td>$ 253,000</td>
<td>$ 253,000</td>
<td>$ 246,534</td>
<td>$ 250,077</td>
<td>$ 258,815</td>
<td>$ 220,475</td>
</tr>
</tbody>
</table>

Source: Department of Water and Power of the City of Los Angeles.

(1) Derived from the Power System Financial Statements.

(2) Net of Uncollectible Accounts.

(3) Excluding depreciation, amortization, accretion and loss on asset impairment and abandoned projects.

(4) Before depreciation, amortization, accretion, interest, extraordinary loss and the Power Transfer.

[Remainder of page intentionally left blank]
Indebtedness

As of January 31, 2015, a total of approximately $8.32 billion in principal amount of indebtedness payable from the Power Revenue Fund was outstanding, comprised of approximately $8.12 billion of revenue Bonds and $200 million of commercial paper. In connection with the Department’s expected capital improvements to the Power System, the Department anticipates that it will issue approximately $4.46 billion of additional debt through June 30, 2019 payable from the Power Revenue Fund. However, the Board is expected to act upon a capital budget for the Power System for Fiscal Year 2015-16 through Fiscal Year 2019-20 at a Board meeting in March 2015. Department staff is expected to recommend a reduction in external/debt financing and total capital expenditures (approximately 10%) as compared to the information provided under “THE POWER SYSTEM – Projected Capital Improvements.” No assurance can be given as to how the Board will act with respect to any proposed capital budget. See “THE POWER SYSTEM – Projected Capital Improvements.”

On May 6, 2014, the Department sold $200 million in principal amount (which is included in the total indebtedness figure above) of its Power System Revenue Bonds, 2014 Series A (the “2014 Series A Bonds”) to Wells Fargo Municipal Capital Strategies, LLC pursuant to a Continuing Covenant Agreement (the “2014A Continuing Covenant Agreement”). The 2014 Series A Bonds are Variable Rate Indebtedness, maturing on July 1, 2038 in an initial SIFMA-based index period ending on May 5, 2017. In the event the amounts become due with respect to the principal of the 2014 Series A Bonds before their maturity or mandatory sinking fund payments, whether upon mandatory tender or acceleration upon an event of default under the 2014A Continuing Covenant Agreement relating to the 2014 Series A Bonds, the Department expects to pay such principal from the remarketing or refunding of the 2014 Series A Bonds or from reserves available to the Power System. The Department does not believe that its obligations with respect to the 2014 Series A Bonds will result in a default under the Department’s other Parity Obligations.

In addition, as of January 31, 2015, the Department was obligated on a “take-or-pay” basis under power purchase or transmission capacity contracts for debt service payments (its share representing approximately $2.35 billion principal amount of bonds) and for operating and maintenance costs of the related projects. The Department has entered into, and may in the future enter into additional, “take-or-pay” contracts in connection with renewable energy projects and other projects undertaken by the joint powers agencies in which it participates. The Department’s obligations to make payments under such “take-or-pay” contracts are unconditional payment obligations. See “—Take-or-Pay Obligations” for the “take-or-pay” contracts the Department has entered as of January 31, 2015. All such commercial paper and “take-or-pay” contract obligations rank on a parity with the Department’s Bonds as to payment from the Power Revenue Fund.

Take-or-Pay Obligations

The Department entered into the IPP Contract and the IPP Excess Power Sales Agreement to purchase up to a 62.79% share of the output of the IPP. The Department has also entered into the UP&L Contract with respect to capacity and energy equal to 4% of the output of the IPP. See “THE POWER SYSTEM – Jointly-Owned Generating Units and Contracted Capacity Rights in Generating Units – Intermountain Power Project.” The Department is also a member of SCPPA and participates in a number of SCPPA projects, including a number of renewable energy projects. See “THE POWER SYSTEM – Renewable Power Initiatives.” The Department’s obligations to make payments with respect to the IPP and the SCPPA projects in which it participates are unconditional “take-or-pay” payment obligations, obligating the Department to make such payments as operating expenses of the Power System whether or not the applicable project is operating or operable, or the output thereof is suspended, interfered with, reduced, curtailed or terminated in whole or in part. The IPP Contract, the IPP Excess Power Sales
Agreement, the UP&L Contract and the agreements with respect to the SCPPA projects contain provisions obligating the Department to pay a share of the cost of any deficit in funds for operating expenses, debt service, other costs related to the project and reserves as a result of a defaulting participant. The Department’s participation and share of bond debt service obligation (without giving effect to any provisions requiring the Department to contribute to any deficiencies upon default by another participant) as of January 31, 2015, for each of the foregoing projects are shown in the following table:

### POWER SYSTEM
**TAKE-OR-PAY OBLIGATIONS FOR BONDS**
**As of January 31, 2015**
**(Dollars in Millions)**
**(Unaudited)**

<table>
<thead>
<tr>
<th>Principal Amount of Outstanding Debt</th>
<th>Department Participation</th>
<th>Department Share of Principal Amount of Outstanding Debt</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Intermountain Power Agency</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>IPP</td>
<td>$1,482(1)</td>
<td>48.62%(2)</td>
</tr>
<tr>
<td><strong>Southern California Public Power Authority</strong> (4)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>PVNGS</td>
<td>36</td>
<td>67.00(4)</td>
</tr>
<tr>
<td>Mead-Adelanto Transmission Project</td>
<td>109</td>
<td>35.70(4)</td>
</tr>
<tr>
<td>Mead-Phoenix Transmission Project</td>
<td>33</td>
<td>24.75(4)</td>
</tr>
<tr>
<td>Linden Wind Energy Project</td>
<td>125</td>
<td>90.00(4)</td>
</tr>
<tr>
<td>Milford Wind Corridor Phase I Project</td>
<td>205</td>
<td>92.50(4)</td>
</tr>
<tr>
<td>Milford Wind Corridor Phase II Project</td>
<td>143</td>
<td>95.10(4)</td>
</tr>
<tr>
<td>Southern Transmission System</td>
<td>658</td>
<td>59.50(4)</td>
</tr>
<tr>
<td>Windy Point Project</td>
<td>447</td>
<td>92.37(4)</td>
</tr>
<tr>
<td>Apex Power Project</td>
<td>319</td>
<td>100.00(4)</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$3,557</strong></td>
<td></td>
</tr>
</tbody>
</table>

Source: Department of Water and Power of the City of Los Angeles.

(1) Includes $121.7 million of commercial paper.

(2) Includes the Department’s obligations under the IPP Contract (44.617%) and the UP&L Contract (4.0%) as described under the caption “THE POWER SYSTEM – Jointly-Owned Generating Units and Contracted Capacity Rights in Generating Units – Intermountain Power Project.”

(3) The Department is the payee of a note receivable from IPA of approximately $774 million as of January 31, 2015, due to the Department’s prepayment of a portion of its share of IPA’s debt.

(4) Equals the Department’s share of SCPPA’s entitlement.

### LITIGATION

**General**

A number of claims and suits are pending against the Department with respect to the Power System for alleged damages to persons and property and for other alleged liabilities arising out of its operations. Certain of these suits are described below. In the opinion of the Department, any ultimate liability which may arise from any of the pending claims and suits is not expected to materially impact the Power System’s financial position, results of operations, or cash flows.
**Owens Gorge**

In 1991, a penstock broke at one of the Department’s hydroelectric plants, causing flooding at the Owens Gorge. In May 1991, the Mono County District Attorney’s Office filed a civil enforcement action entitled *People v. Los Angeles Department of Water and Power and State Water Resources Control Board, et al.*, in Mono County Superior Court (Case No. 10088), seeking an order for the Department to restore stream flows in the Owens Gorge in efforts to reestablish fisheries. In January 2015, a stipulated judgment was entered into that establishes a permanent injunction that will reduce the amount of water available for hydroelectric generation at the Owens Gorge Hydroelectric Development. This action is not related to the Department’s lower Owens River restoration project, which reintroduced water to a portion of the lower Owens River in December 2006. See “THE POWER SYSTEM—Department-Owned Generating Units—Owens Gorge and Owens Valley Hydroelectric Generation.”

**Dairy Cow Litigation**

In February 2005, a number of dairy farmers in Utah filed a lawsuit in the Fourth District Court, State of Utah, entitled *Gunn Hill Dairy Properties, LLC, et al. v. Los Angeles Department of Water and Power, et al.*, Case No. 050700157, naming the Department, IPA and others as defendants (the “Utah Dairy Case”). The Department is named in the Utah Dairy Case in both its individual capacity and as operating agent for IPA. The suit generally alleges that since 1987, “stray voltage” emitted from the IPP facilities through the ground and ground water damaged the dairy herds, including causing higher than normal death rates, a reduction in milk production and an impairment to the cows’ immune systems. The matter proceeded with six of the original plaintiffs (the “Original Six Plaintiffs”) involved in an initial trial. It is contemplated that the remainder of the plaintiffs will have one or more additional trials. The Original Six Plaintiffs amended their economic damages report to seek compensatory damages in excess of $515,000,000, plus punitive damages. The separate trial or trials for the other two plaintiff groups have not yet commenced.

In November 2013, a mistrial was declared in the Utah Dairy Case relating to the Original Six Plaintiffs. The mistrial was declared based on juror misconduct involving communications by a juror with persons that have not been parties to the litigation.

After the mistrial, the defendants filed a motion for judgment notwithstanding the verdict asserting that the Original Six Plaintiffs had failed to produce enough evidence to submit the case to a jury. On April 29, 2014, the court granted the motion in part and denied it in part. The court dismissed all but one of the Original Six Plaintiffs’ claims, including their claim for punitive damages, but left open for a further jury trial the Original Six Plaintiffs’ claim of negligence. Neither party appealed the court’s order with respect to the motion, and the time to seek leave to do so has now passed.

Also following the mistrial, the Original Six Plaintiffs filed a motion for sanctions and for a change of venue. On August 29, 2014, the court denied the motion both for sanctions and for a change of venue. On October 6, 2014, the court entered a formal order to that effect. On October 9, 2014, the Original Six Plaintiffs filed a petition for leave to appeal the October 6 order. The Utah Supreme Court transferred the petition to the Utah Court of Appeals. On November 5, 2014, the Utah Court of Appeals granted the petition for leave to appeal the denial of the motion to change venue, but denied permission to appeal the trial court’s denial of the Original Six Plaintiffs’ motion for sanctions. Plaintiffs then filed a motion in the trial court to stay the proceedings in the trial court pending the outcome of the appeal. The Department and other defendants opposed the motion. By order dated December 2, 2014, the trial court stayed all proceedings before it, pending resolution of the appeal.

Because a mistrial was declared during the first trial, the claims of the Original Six Plaintiffs will need to be re-tried. The trial court set summer 2015 dates for the re-trial.
The Department believes that on the law and facts, defendants should prevail, and thus the Department does not expect that the Utah Dairy Case, or any similar claims, would have a material adverse effect on the Power System. However, given, among other factors, that the court declined to dismiss the Original Six Plaintiffs’ negligence claim and will allow it to be presented to a jury, and the unpredictable nature of a jury trial, the Department cannot predict the outcome of the plaintiffs’ claims. In the event there is an adverse judgment in this litigation, the award of substantial damages from such claims could materially affect the costs of power from IPP, may affect the continued economic viability of IPP, and could impact the costs of operating the Power System.

**Powerhouse Fire**

In May 2013, a fire ignited in the San Francisquito Canyon area, in close proximity to the Department’s generating unit named Powerhouse No. 1 ("Powerhouse No. 1"), which ultimately burned 53 structures, including 24 homes, and over 30,000 acres (the "Powerhouse Fire"). For information about the facilities located near San Francisquito Canyon, see “THE POWER SYSTEM – Department-Owned Generating Units – San Francisquito Canyon and the Los Angeles and Franklin Reservoirs.” Approximately 650 claims for damage have been received and 16 Superior Court lawsuits have been served against the Department by individuals and insurance carriers (subrogation actions) that involve approximately 230 plaintiffs. In general, the cases allege that the Department caused the Powerhouse Fire by negligently operating and maintaining the power lines and related equipment at or near Powerhouse No. 1. The main alternative theory is that the fire was an inverse condemnation, the taking of private property without just compensation. The one year statute of limitations for the filing of tort related claims terminated in June 2014, with lawsuits based on those tort claims needing to be filed by June 2015. The three year statute of limitations for inverse condemnation based lawsuits, for which no claim for damage needs to be filed, terminates in June 2016. Pursuant to a court order, all present and future State litigation matters relating to the Powerhouse Fire have been coordinated and deemed complex and assigned to the Complex Civil Litigation Program of the Los Angeles Superior Court.

In addition to the pending litigation cases, the United States Forest Service ("USFS") issued a report that concluded the cause of the Powerhouse Fire was Department Power System equipment and has asserted claims of monetary damages in excess of $31 million. A lawsuit seeking those damages is expected to be filed in Federal Court by the USFS in the next several months.

The Department has also been conducting an investigation into all potential causes of the Powerhouse Fire, which remains ongoing. Experts retained by the Department are focusing on both liability and damage issues. The Department’s financial exposure regarding this matter include USFS fire suppression and forest ecological damage, insurance subrogation claims and cases, and individual property damage and loss claims and cases. The Department cannot predict the ultimate liability of the Department; however, due to the Department’s general liability insurance and current financial condition (including available self-insurance reserve funds), any liability relating to the Powerhouse Fire is not expected to have a material adverse effect on the operations or financial condition of the Power System.

**Tesoro Refinery Litigation**

On September 22, 2010, the Court of Appeal of the State of California issued its decision in the case of City of Los Angeles v. Tesoro Refining and Marketing Company (No. B217790). The case involved providing power to the oil refinery (the “Refinery”) of Tesoro Refining and Marketing Company (“Tesoro”) in connection with the Tesoro’s development of facilities to self-serve the electric requirements of the Refinery, which requires the provision of stand-by service at a single voltage level. The Refinery straddles the service territory, and was a partial requirements customer, of both the Department and Edison, with each utility providing service at different voltage levels. The court disagreed with the City’s position that the State Constitution and the Charter provided the City the right to...
sell all power consumed within the City limits. The court relied on a 1955 California Supreme Court case as authority for the principles that the regulation of private utilities is a statewide concern which the State has delegated to the PUC and not a municipal affair subject to city charters. The court relied on the same case as authority for the principle that the franchise powers of cities are limited to authorizing the use of public streets and other public property and do not extend to regulating the business of an entity in providing utility service. The court concluded that neither the State Constitution nor the Charter prohibited Tesoro from buying electricity from Edison at a point outside the City, transporting that electricity over the Refinery’s internal wiring, and using that electricity in those portions of the Refinery located within the City. The City submitted a petition for review of the decision to the California Supreme Court, but the California Supreme Court has denied such petition.

Given Tesoro’s self-generation plan, the Department does not expect that the decision in the litigation will have a material adverse effect on the financial condition of the Power System. The Department cannot predict what effect the precedent of the decision to this litigation will have on the Power System with respect to other instances of entities providing electric service on private property within the City, that is service which does not require the use of any public streets or other public property. The issues raised by the litigation may apply more broadly than just to the Department.

City Lawsuit Against Certain Underwriters

On July 23, 2008, the City filed a complaint in the Superior Court for the County of Los Angeles, California, Case Number BC394944, which named a number of defendants, some of which serve, or have affiliates that serve, as underwriters of bonds issued by the Department. The complaint alleges that the defendants conspired to manipulate the municipal derivatives market by various means to decrease the returns the City earned on municipal derivatives instruments, including guaranteed investment contracts and swaps. The complaint was removed to federal district court in the Central District of California on August 25, 2008 and subsequently transferred for pre-trial coordination with other related actions in the Multidistrict Litigation (“MDL”) pending in the Southern District of New York, MDL No. 1950, Master Docket Number 08-CV-02516 (VM). On April 26, 2010, the court presiding over the MDL denied certain defendants’ motions to dismiss the City’s complaint. The case has now entered into the discovery phase. Neither the City nor the derivative provider affiliates of such underwriters can predict the outcome of the lawsuit.

The Department is not a party to the municipal derivatives litigation; however the Department has filed a complaint against several bond insurance providers alleging among other things, fraud and deceit. There can be no assurance that the Department will not become a party to the pending litigation or other similar litigation against any of the municipal derivative provider affiliates of the underwriters of bonds issued by the Department.

[Remainder of page intentionally left blank]
The following is information concerning the City of Anaheim (“Anaheim”) and its departments and agencies, including Anaheim’s Public Utilities Department (the “Anaheim Public Utilities Department” or “Department”) and such Department’s electric utility (the “Anaheim Electric System” or the “Electric System”), prepared by Anaheim for inclusion herein. This information does not purport to cover all aspects of the Anaheim Electric System’s business, operations and financial position. A copy of the most recent annual report of the Anaheim Electric System may be obtained from the Financial Services Manager/Controller, Anaheim Public Utilities Department, 201 South Anaheim Boulevard, Suite 902, Anaheim, California 92805.

General

The Anaheim Electric System was established in 1894. The original Anaheim-owned generating plant was placed in service in 1895 and consisted of a steam-driven generator of 500 lights capacity. By 1896, the maximum capacity of the original generating plant had been reached and Anaheim voters authorized bonds for the combined rebuilding of both the electric light plant and the Anaheim water system (the “Water System”). In 1916, Anaheim entered into an agreement to purchase electricity at wholesale rates from Southern California Edison (“Edison”) rather than generate its own power. In 1934, Anaheim, working with the federal Public Works Administration, rebuilt and expanded the distribution system sufficiently to serve the needs of its citizens until the end of World War II. Anaheim has since continued to expand its distribution system to meet the growing demands of its customers.

From 1916 through 1982, Anaheim met substantially all of its electric capacity and energy requirements by purchases from Edison.

In the mid-1970s, Anaheim instituted a program to meet its electric capacity and energy requirements from its own resources and by long-term purchases from sources other than Edison, taking the first capacity and energy from such resources in 1983. As a result of this program, beginning in the fiscal year ended June 30, 2001, Anaheim purchased none of its energy requirements from Edison. For the fiscal year ended June 30, 2014, the average number of customers of the Electric System was 115,474 and the total megawatt-hours (“MWh”) sold to retail customers was 2,357,000. Anaheim is in the process of changing the resource mix of its power portfolio, decreasing its reliance on coal and increasing its use of natural gas-generated power and renewable energy resources. See “Renewable Portfolio Standard” below.

Management

Under the provisions of the California Constitution, the Charter and Title 10 of the Municipal Code of Anaheim, Anaheim owns and operates both the Electric System and the Water System for the citizens of Anaheim. The Anaheim Public Utilities Department exercises jurisdiction over both the Electric System and the Water System and is under the supervision of the Public Utilities General Manager (the “General Manager”). The General Manager is responsible for the supervision of the design, construction, maintenance and operation of both the Electric System and the Water System. The Finance Director of Anaheim is charged with the accounting and the administration of the financial affairs of Anaheim. The General Manager and Finance Director are under the direction of the City Manager who is appointed by the City Council.

The Department provides electricity as well as water to virtually all the residential, commercial and industrial customers within the city limits of Anaheim. The funds and accounts of the Electric System and the Water System are held separately, and the funds and accounts of one system are not pledged to the other system’s obligations.
**Dukku Lee,** Public Utilities General Manager, has been with the Anaheim Public Utilities Department since November 1999 and was appointed General Manager in November 2013. He has full management responsibility to plan, direct, and manage the day-to-day activities and operations of the Department. Mr. Lee has 20 years of utility industry experience, including 14 years in municipal electric utilities management. Prior to his appointment as General Manager, Mr. Lee held the position of Assistant General Manager–Electric Services with responsibility for managing the engineering, construction, operation and maintenance of the utility generation, transmission, and distribution system. Mr. Lee has previously worked for Southern California Edison (“Edison”) and Paragon Consulting Services. Mr. Lee holds a Bachelor of Science degree in Electrical Engineering from California State Polytechnic University, Pomona and a Master of Science degree in Engineering Management from California State University, Long Beach and is a registered Professional Engineer in the State of California. Mr. Lee is on the Board of Directors of the Southern California Public Power Authority (“SCPPA”) and the California Municipal Utilities Association (“CMUA”).

**Brian Beelner,** Assistant General Manager – Finance and Administration, joined the Anaheim Public Utilities Department in May 2005. Mr. Beelner has 14 years of experience in utility finance and accounting. He is responsible for all financial aspects of the Department including: accounting, budget development, strategic planning, rate design, long-term forecasting, debt administration, human resources, safety, and billing and collection services. Mr. Beelner graduated from University of California-Riverside with a Bachelor of Arts degree in Business Economics and currently holds an active Certified Public Accountant license in the State of California. Prior to joining Anaheim, Mr. Beelner worked for Gursey, Schneider & Co., LLP as a municipal utility accounting and finance consultant. Mr. Beelner is also a member of the SCPPA Finance Committee and a member of the Finance Committee for the Intermountain Power Project (“IPP”).

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

The Assistant General Manager – Power Supply retired from Anaheim in December 2014. The position is currently under recruitment.

**Principal Facilities**

As of June 30, 2014, the principal facilities of the Anaheim Electric System consisted of transmission and distribution lines totaling 1,172 circuit miles, 12 distribution substations, Anaheim’s 10.04% ownership interest in Unit 4 of the San Juan Generating Station located in northwest New Mexico (“San Juan”), and Anaheim’s Kraemer Combustion Turbine Plant (the “CT Plant”) located within Anaheim’s city limits. The capacity available to Anaheim from San Juan is approximately 50 MW. The CT Plant became commercial in 1991. The capacity available from the CT Plant is 48 MW in the winter and 46 MW in the summer.

**Power Supply**

The electric resources of Anaheim currently consist of power from Anaheim’s ownership interests in San Juan and the CT Plant, purchases of firm power under entitlements in IPP, SCPPA’s
Hoover Uprating Project, SCPPA’s Magnolia Power Project and SCPPA’s Canyon Power Project (in which Anaheim has an entitlement to 100% of the capacity and energy thereof) and firm power purchases and non-firm energy purchases from other utilities. In the fiscal year ended June 30, 2014, Anaheim generated and purchased approximately 4,231,722 MWh of electricity. Combined customer electric requirements created the historic distribution system peak demand of 593 MW on July 24, 2006. The following table sets forth the total Electric System gigawatt-hours (“GWh”) of energy generated and purchased and electric distribution system peak demand during the five fiscal years shown:

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

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Owned Generation:</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>San Juan</td>
<td>387</td>
<td>331</td>
<td>385</td>
<td>392</td>
<td>333</td>
</tr>
<tr>
<td>Kraemer CT</td>
<td>80</td>
<td>79</td>
<td>45</td>
<td>39</td>
<td>78</td>
</tr>
<tr>
<td>Subtotal</td>
<td>467</td>
<td>410</td>
<td>430</td>
<td>431</td>
<td>411</td>
</tr>
<tr>
<td><strong>Firm Purchases:</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Intermountain Power Project(1)</td>
<td>1,558</td>
<td>1,413</td>
<td>1,338</td>
<td>1,485</td>
<td>1,903</td>
</tr>
<tr>
<td>Hoover</td>
<td>45</td>
<td>43</td>
<td>47</td>
<td>44</td>
<td>40</td>
</tr>
<tr>
<td>Magnolia(2)</td>
<td>712</td>
<td>364</td>
<td>625</td>
<td>434</td>
<td>651</td>
</tr>
<tr>
<td>Canyon Power Project</td>
<td>88</td>
<td>119</td>
<td>55</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td>Renewable Resources(3)</td>
<td>1,066</td>
<td>565</td>
<td>263</td>
<td>269</td>
<td>248</td>
</tr>
<tr>
<td>Subtotal</td>
<td>3,469</td>
<td>2,504</td>
<td>2,328</td>
<td>2,232</td>
<td>2,842</td>
</tr>
<tr>
<td><strong>Non-Firm Purchases:</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>System Total Energy Generated and Purchased, GWh(4)</td>
<td>4,232(5)</td>
<td>3,440</td>
<td>3,108</td>
<td>3,168</td>
<td>3501</td>
</tr>
<tr>
<td>Distribution System Peak Demand, MW</td>
<td>549</td>
<td>542</td>
<td>549</td>
<td>580</td>
<td>545</td>
</tr>
</tbody>
</table>

(1) In Fiscal Year 2011, IPP Units 1 and 2 were down for maintenance during the STS upgrade; in Fiscal Year 2012, Unit 1 was down for six months and in Fiscal Year 2013, Unit 1 and 2 were down for two months due to a planned outage.

(2) In Fiscal Year 2013, Magnolia was down for maintenance for approximately four and a half months.

(3) In Fiscal Year 2013, renewable energy resources were higher to meet the RPS requirement of 20% of total energy resources by the end of 2013.

(4) Includes energy purchased that was ultimately sold to other utilities. Also includes renewable energy credits (“RECs”) purchased.

(5) Reflects increased wholesale activity under existing market conditions.

Source: Anaheim.

Anaheim’s power supply comes from a variety of electric generating resources in order to provide lower rates and reliable service to its customers. Anaheim also supports environmentally sound energy generation, and has plans to increase renewable resources as part of its overall power portfolio. See “– Renewable Energy Resources” below.

As described above, Anaheim has a 10.04% (50 MW) undivided ownership interest in Unit 4 of the San Juan Generating Station, located in San Juan County in northwestern New Mexico, near Farmington, New Mexico. The San Juan Generating Station is a source that is subject to the statutory obligations of the federal Clean Air Act to reduce visibility impacts. Regulatory proceedings and other related litigation concerning the application of federal Clean Air Act requirements at the San Juan Generating Station have been ongoing. In June 2014, the nine owners of San Juan reached a non-binding agreement in principle on an ownership restructuring of San Juan that, if implemented, would result in the retirement of the San Juan Generating Station Units 2 and 3 by December 31, 2017 and the installation of selective non-catalytic reduction technology on Units 1 and 4 as part of the overall settlement of matters regarding emissions at San Juan. Under the non-binding agreement for the proposed ownership restructuring, Anaheim would divest its ongoing participation in Unit 4 as of December 31, 2017, with Anaheim’s ownership interest to be acquired by PNM and the City of Farmington (“Farmington”).
However, in early January 2015, Farmington announced that it had determined not to acquire an additional ownership interest in Unit 4. Anaheim is unable to predict whether any proposed restructuring of the ownership of the San Juan Generating Station, including the currently proposed restructuring whereby Anaheim would divest its ongoing participation in Unit 4 effective December 31, 2017, will ultimately be implemented. Anaheim continues to evaluate its options and the economics surrounding continued participation in San Juan.

**Renewable Energy Resources**

Consistent with State legislation, Anaheim has adopted a Renewable Portfolio Standard (the “RPS”) that sets a target of increasing its purchases of eligible renewable energy resources to 33% within three multi-year compliance periods through 2020. Anaheim has met the 20% compliance period target for 2011-2013, and is currently on track to reach the 25% compliance period target for 2014-2016, and the 33% compliance period target for 2017-2020.

Anaheim has purchased 32 MW of wind generated energy from PPM Energy under two separate contracts. Wind energy typically comes with a 33% load factor, so the PPM Energy contracts effectively represent 12 MW of resources. The first contract is delivered 24 hours-a-day at 2 MW and priced at $53.50/MWh which is fixed over the 20-year life of the contract, which began July 1, 2004. The second contract for 30 MW (effectively 10 MW) is priced at $55/MWh which is also fixed over the life of the contract with a 20-year term beginning July 1, 2005. This contract is deemed “as-available” and delivered through the Northern Transmission System at the Mona interconnection tie in the LADWP control area. Anaheim receives and pays for energy only when the units are operating.

Anaheim has contracted with Ormat Technologies, through SCPPA, for a geothermal project with Anaheim’s share of the project totaling 8.4 MW. The project came on line on January 1, 2006 and is priced at $57.50/MWh with an annual escalation rate of 1.5% per year. The energy is delivered at the interconnection with IID at the Mirage Interconnection tie. The term of the contract is for a minimum of 15 years with an option to extend an additional five years.

Anaheim executed Power Purchase Agreements with Brea Power Partners, LP to deliver landfill gas renewable energy. The first contract was a short-term, 5 MW contract with a start date of April 1, 2007 (with power received commencing July 9, 2007) from an existing facility at the Olinda Landfill through (i) the commercial operation date of a second unit or (ii) December 31, 2013. The price for energy from the Olinda Landfill project was $69.00/MWh through December 31, 2008 and then increased to $71.00/MWh on January 1, 2009, with an annual price escalation thereafter of 2% commencing January 1, 2010. The original contract was superseded by a second long-term contract for a total of 27 MW from the new unit at the Olinda Landfill project upon commercial operation of the second unit, which occurred in November 2012. The term of the 27 MW contract is 33 years. The price is $112.5/MWh with no escalation over the term of the contract.

Anaheim executed a Power Purchase Agreement with a Raser Technologies subsidiary corporation for an 11 MW geothermal project. The project is located in central Utah and energy is being delivered to Anaheim over the Northern Transmission System at the Mona interconnection tie in the LADWP control area. The original energy cost was $78/MWh with a 2% annual escalation factor. There was an additional transmission cost to Anaheim of $2.98/MWh to get delivery to the Mona interconnection point. The project began commercial operation in April 2009. The term for the agreement was 20 years. On or about April 29, 2011, Raser Technologies, Inc. and its Affiliated Debtors filed voluntary petitions for relief under the Bankruptcy Code. The Bankruptcy Court on August 30, 2011 confirmed the Third Amended Plan of Raser Technologies, Inc. and its Affiliated Debtors with a Plan effective date of September 9, 2011. Raser Technologies changed its name to Cyrq Energy Inc. The Bankruptcy Court approved the reorganized subsidiary corporation’s assumption of its Power Purchase Agreement with Anaheim. As the result of a generator upgrade completed on November 1, 2013 to
include an Ormat Energy Converter with a nameplate capacity of 14,000 gross kW, the agreement with the new Cyrq Energy Inc. subsidiary was amended. The amended 20-year agreement of up to 11 MW expires in 2033. The energy cost is $98.50/MWh with a 2% annual escalation factor and transmission costs of $3.13/MWh.

Anaheim has contracted with The Metropolitan Water District of Southern California, through SCPPA, for 10 MW of hydro electricity from a variety of small power plants located at various sites within the Los Angeles Basin. The power is run-of-the-river hydro as opposed to storage hydro and as such, is deemed energy “as available,” much like wind. The power is priced at $94.83/MWh, and delivery began November 1, 2008. The contract expires on December 23, 2023.

Anaheim executed a Power Purchase Agreement with San Gorgonio Farms, Inc. for 31 MW of wind energy from the existing San Gorgonio Farms Wind Farm located in Whitewater, California. This facility reached commercial operation in 1983 and was originally under contract to Edison. The price for power is split between the environmental attributes and energy. Environmental attributes are priced at $38.50/MWh with no escalation and the energy price is equal to the revenue paid by the California Independent System Operator (“ISO”) for delivery of the project’s energy less all ISO charges, fees, debits, costs, penalties, and interest assigned to the project. This agreement has an initial term of ten years ending 2024 with the option to extend for two additional 10-year periods.

Anaheim executed a Power Purchase Agreement with Anaheim Energy, LLC for 4 MW of energy from anaerobic digestion of organic municipal solid waste. The power project is to be located in Anaheim and has an anticipated commercial operation date of December 30, 2015. Power under this agreement is priced at $142.90/MWh escalated at 2% annually less all ISO charges, fees, debits, costs, penalties, and interest assigned to the project. The term of this agreement is initially 20 years with one option to extend for an additional five years.

Anaheim executed a Power Purchase Agreement with Bowerman Power, LLC for the purchase of 19.6 MW of energy generated from landfill gas from the Frank R. Bowerman Landfill in Irvine, California. The proposed generating facility is projected to produce 154 GWh annually, beginning in January 2016. The annual total cost for the renewable energy and RECs is estimated to be $13.5 million with a 2.5% escalator during the first 10 years, 1.5% for the next five years, and no escalator thereafter. The initial price under the agreement is $87.40/MWh less all ISO charges, fees, debits, costs, penalties, and interest assigned to the project. The term of this agreement is 20 years.

Anaheim executed a Power Purchase Agreement with Westside Assets, LLC for 2 MW of solar energy in Kings County, California. This Power Purchase Agreement was subsequently amended on December 23, 2014 to clarify language and allow for a revision to the construction schedule. This project is anticipated to be commercially operational by November 2015. Power under this agreement is priced at $91.00/MWh fixed for the term less all ISO charges, fees, debits, costs, penalties, and interest assigned to the project. The term of this agreement is 25 years.

Anaheim’s ISO Arrangements

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

In June 2002, Anaheim notified the ISO of its intent to become a Participating Transmission Owner (“PTO”) by turning over operational control of Anaheim’s transmission entitlements. In November 2002, Anaheim executed the Transmission Control Agreement between the ISO and the PTOs. On January 1, 2003, Anaheim became a PTO under the ISO tariff by turning over operational control of
its transmission entitlements to the ISO. In return, Anaheim receives payment of its revenue requirement for such facilities from the ISO. Anaheim now obtains all of its transmission scheduling requirements from the ISO, and it procures additional ancillary services required from the ISO or from the open competitive market. At this time, Anaheim’s transmission revenue requirement has been approved by the Federal Energy Regulatory Commission (“FERC”), and there are no outstanding contested issues associated with Anaheim’s transmission revenue requirement.

Customers and Energy Sales

The Electric System serves the entire area within the Anaheim city limits (an area of approximately 50 square miles). The following tables set forth the average number of customers and total electrical energy sold (in megawatt hours) during the five fiscal years shown.

### AVERAGE NUMBER OF CUSTOMERS

<table>
<thead>
<tr>
<th></th>
<th>Fiscal Year Ended June 30,</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2014</td>
</tr>
<tr>
<td>Residential</td>
<td>98,382</td>
</tr>
<tr>
<td>Commercial</td>
<td>16,657</td>
</tr>
<tr>
<td>Industrial</td>
<td>302</td>
</tr>
<tr>
<td>Other</td>
<td>117</td>
</tr>
<tr>
<td>Other Utilities</td>
<td>16</td>
</tr>
<tr>
<td>Total – All Classes</td>
<td>115,474</td>
</tr>
</tbody>
</table>

### TOTAL ENERGY SOLD

(000’s of MWh)

<table>
<thead>
<tr>
<th></th>
<th>Fiscal Year Ended June 30,</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2014</td>
</tr>
<tr>
<td>Residential</td>
<td>570</td>
</tr>
<tr>
<td>Commercial</td>
<td>708</td>
</tr>
<tr>
<td>Industrial</td>
<td>1,051</td>
</tr>
<tr>
<td>Other</td>
<td>28</td>
</tr>
<tr>
<td>Other Utilities</td>
<td>1,721</td>
</tr>
<tr>
<td>Total – All Classes</td>
<td>4,078 (2)</td>
</tr>
</tbody>
</table>

(1) The difference between the total MWh generated and purchased shown in the table above captioned “Total Megawatt Hours (MWh) Generated and Purchased (000’s) and Peak Demand (MW)” and total MWh sold is due to transmission and distribution system losses, wholesale transactions and RECs.

(2) Reflects increased wholesale activity under existing market conditions.

Source: Anaheim.

As a percentage, the total energy sold to retail customers represents approximately 60% of the total energy Anaheim generated itself and obtained through firm purchases for the fiscal year ended June 30, 2014.
Major Customers

The ten largest power customers of the Anaheim Electric System, in terms of kilowatt hour (“kWh”) sales, accounted for approximately 20% of the Electric System’s total energy sales for the fiscal year ended June 30, 2014. The largest power customer accounted for approximately 12% of total energy sales for such fiscal year.

In connection with an expansion of the Disneyland Resort located in Anaheim, Anaheim entered into an agreement with The Walt Disney Company (“Disney”), pursuant to which Anaheim and Disney agreed that Anaheim would provide all electricity required by Disney for the operation of the Disneyland Resort. Power purchased by Disney under such agreement was at a discount from otherwise applicable rate schedules of Anaheim. From and after July 1, 2005, the agreement allowed Disney to purchase all or a portion of its electric power requirements from a supplier other than Anaheim if Anaheim was at that time permitting other customers with similar load characteristics to purchase electric power from other suppliers. The right of Disney to purchase power from other suppliers was subject to the right of Anaheim to match the economic terms of any new purchase, in which event, Disney would have been obligated to accept Anaheim’s offer and purchase that portion of its electric power covered by any such offer from Anaheim. Disney did not purchase power from any other supplier for its Anaheim facilities. The term of the agreement with Disney extended to December 31, 2013, with options exercisable by Anaheim and Disney for additional six-month extensions until December 31, 2014. These options were not exercised and the agreement terminated on December 31, 2013. Disney currently operates under the established Electric Rates, Rules and Regulations of Anaheim. Disney does not receive any discounts or other terms that are not otherwise available to other customers of Anaheim.

Electric Rates and Charges

Anaheim is obligated by the Anaheim Charter and by certain resolutions of Anaheim’s City Council under which it has electric revenue bonds outstanding to establish rates and collect charges in an amount sufficient to service Anaheim Electric System’s indebtedness, to meet its expenses of operation and maintenance and to pay other obligations payable from gross revenues, with specified requirements as to priority and coverage.

Electric rates are established by Anaheim’s City Council and are not subject to regulation by the CPUC or by any other state agency. The rates charged by Anaheim to its customers are not subject to approval by any federal agency; however, the Public Utility Regulatory Policies Act (“PURPA”) requires state regulatory authorities and nonregulated electric utilities, including Anaheim, to consider certain rate-making standards and to make certain determinations in connection therewith. Anaheim believes that it is operating in compliance with PURPA.

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

The Anaheim Electric System has a number of base rate schedules. Generally, all costs of the Anaheim Electric System, including power supply costs, are recovered through the application of these base rates. Anaheim’s customer rates also include a Rate Stabilization Adjustment (“RSA”) that increases or decreases specifically for the recovery of the respective fluctuations in power supply, relevant operational costs and environmental mitigation costs to meet specified financial performance indicators and goals. These goals stated within the rate schedule include the maintenance of debt service coverage ratios no less than 1.5 times and a balance in the account for deferred inflows (RSA collections balancing account) equal to approximately $50 million.
The RSA contains two components: the Power Cost Adjustment (“PCA”) and the Environmental Mitigation Adjustment (“EMA”). The PCA is structured so that it can increase up to $0.5¢ per kWh in any 12-month period to collect for changes in power production costs, purchased power costs, regulatory compliance costs, debt service and any other costs involved in delivering energy. Additionally, if the Electric System’s power supply or fuel costs increase by more than 10% over originally budgeted levels for a period of one month or longer or if the Electric System loses a major resource, such as a generation or transmission unit, then the Electric System may increase the PCA by an additional $1¢/kWh over and above the current $0.5¢ limit until all associated costs are collected at which time the PCA will be reduced to its previous level. This provision was used to recover costs related to the previously described outage at IPP. The second component of the RSA, the EMA, allows for the recovery of environmental mitigation costs such as: projected greenhouse gas emissions costs, the marginal cost differential between renewable power and traditional carbon-based power, and environmental mitigation costs imposed by regulatory bodies, legislative mandates or judicial settlements, orders or decrees. The EMA is structured similarly to the PCA in that the annual limit of the increase is $0.5¢/kWh unless costs increase by more than 10% of projections, at which point the EMA’s limit on annual increases may be increased by an additional $1¢/kWh until all associated costs are collected, and at that time the EMA will be reduced to its previous level.

The RSA collections are treated as deferred inflows for accounting purposes and are used by management to mitigate material fluctuations in the cost of energy, loss of revenues or unbudgeted costs including the unexpected long-term loss of a generating facility, unplanned limits on the ability to transmit energy to Anaheim, or disasters that could otherwise negatively affect the revenue stream. At management’s discretion, amounts in the RSA accounts may be withdrawn and recognized as gross revenues of the Electric System in order to maintain sufficient debt service coverage ratios. As of June 30, 2014, the balance in the RSA deferred inflows account was approximately $89 million.

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

Currently, the PCA charge is $1.50¢/kWh for all usage by residential customers, above prescribed base (first tier) levels, and is $1.00¢/kWh for commercial usage, industrial usage and municipal customers. The EMA charge is currently $1.50¢/kWh for all residential customers and $1.00¢/kWh for all other customers regardless of the amount of energy used. In addition, all classes pay an undergrounding surcharge equal to 4% of base rate charges (exclusive of the RSA) in order to fund the conversion of overhead power lines into underground lines throughout Anaheim. Anaheim does not impose a utilities’ user tax. The base electric rates were last revised by Anaheim’s City Council on November 9, 2010. This action increased the base electric rates by 10% overall with a 5% increase on December 1, 2010 and another 5% increase on December 1, 2011. There have not been any additional changes to the base rates since December 1, 2011.

The table below sets forth the average billing price per kWh for the various customer classes during the five fiscal years shown (taking into account the PCA, the EMA and the 4.00% undergrounding surcharge).
### AVERAGE BILLING PRICE (CENTS) PER KILOWATT-HOUR
(RETAIL SALES)

<table>
<thead>
<tr>
<th></th>
<th>Fiscal Year Ended June 30,</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2014</td>
</tr>
<tr>
<td>Residential</td>
<td>16.64</td>
</tr>
<tr>
<td>Commercial</td>
<td>16.79</td>
</tr>
<tr>
<td>Other</td>
<td>14.03</td>
</tr>
<tr>
<td>System Averages</td>
<td>15.49</td>
</tr>
</tbody>
</table>

Source: Anaheim.

### Capital Improvements Plan

As part of its planning process, Anaheim has identified the following Electric System capital improvement projects through the fiscal year ending June 30, 2019 (the “Five-Year Plan”), totaling approximately $266.3 million:

#### Five-Year Plan
($000)

<table>
<thead>
<tr>
<th></th>
<th>2015-2019</th>
</tr>
</thead>
<tbody>
<tr>
<td>Transmission and Distribution</td>
<td>$100,104</td>
</tr>
<tr>
<td>System Undergrounding</td>
<td>81,450</td>
</tr>
<tr>
<td>New Substations</td>
<td>45,300</td>
</tr>
<tr>
<td>Substation Improvements</td>
<td>20,772</td>
</tr>
<tr>
<td>System Automation</td>
<td>13,365</td>
</tr>
<tr>
<td>Telecommunication</td>
<td>5,350</td>
</tr>
<tr>
<td>Total</td>
<td>$266,341</td>
</tr>
</tbody>
</table>

Projects involving the Electric System’s electricity distribution substations include enhancements to existing substations, such as new transformers, circuit breakers, and switchgear that will improve reliability and provide sufficient capacity for anticipated electric load growth. Harbor Substation, a new substation planned for the fiscal year ending June 30, 2019, will provide additional load from the Platinum Triangle and Anaheim Resort Area. Another component of the Electric System’s capital improvement plan involves projects to replace aging overhead electrical and communication facilities with new state-of-the-art underground facilities, in order to improve overall system reliability, public safety, and aesthetics. In addition, the Electric System’s capital improvement plan provides for the repair and replacement of existing overhead and underground facilities. Other capital projects include replacing aging transformers, vaults, switches, cable and utility poles, as well as system reliability enhancements for equipment automation, supervisory control and data acquisition (“SCADA”) and telecommunications projects. Anaheim funds its capital plan through a combination of long-term financing, pay-as-you-go, and other resources. Anaheim is in the bond market on a periodic basis to fund appropriate capital projects based on its planning models. Anaheim currently anticipates it will finance approximately $140 million of the capital costs identified in the Five-Year Plan.

### Historical Financial Results

The table on the following page shows a summary of the financial results of the Electric System, together with calculation of debt service coverage of outstanding Electric System obligations for the five fiscal years shown.
## CITY OF ANAHEIM
### ELECTRIC UTILITY FUND, FINANCIAL RESULTS OF THE ELECTRIC SYSTEM

($000)

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Restated</strong> Restated</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Revenues</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sale of electricity:</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Residential</td>
<td>$ 81,339</td>
<td>$ 86,763</td>
<td>$ 80,865</td>
<td>$ 76,620</td>
<td>$ 74,327</td>
</tr>
<tr>
<td>Commercial</td>
<td>105,636</td>
<td>105,904</td>
<td>102,374</td>
<td>96,416</td>
<td>84,981</td>
</tr>
<tr>
<td>Industrial</td>
<td>124,794</td>
<td>131,381</td>
<td>128,708</td>
<td>123,383</td>
<td>119,229</td>
</tr>
<tr>
<td>Other</td>
<td>3,591</td>
<td>2,858</td>
<td>2,438</td>
<td>2,875</td>
<td>2,974</td>
</tr>
<tr>
<td>Other Utilities (wholesale)</td>
<td>42,374</td>
<td>26,322</td>
<td>19,506</td>
<td>21,039</td>
<td>35,409</td>
</tr>
<tr>
<td><strong>Billed revenue from sale of electricity</strong></td>
<td>$357,734</td>
<td>$353,228</td>
<td>$333,891</td>
<td>$320,333</td>
<td>$316,920</td>
</tr>
<tr>
<td><strong>Change in unbilled electric revenue</strong></td>
<td>1,556</td>
<td>2,405</td>
<td>(464)</td>
<td>1,228</td>
<td>1,456</td>
</tr>
<tr>
<td><strong>Total revenue from sale of electricity</strong></td>
<td>$359,290</td>
<td>$355,633</td>
<td>$333,427</td>
<td>$321,561</td>
<td>$318,376</td>
</tr>
<tr>
<td>RSA revenue</td>
<td>26,500</td>
<td>41,000</td>
<td>24,000</td>
<td>22,500</td>
<td>31,200</td>
</tr>
<tr>
<td>Other (including general interest income)</td>
<td>44,992</td>
<td>57,316</td>
<td>48,167</td>
<td>44,873</td>
<td>40,788</td>
</tr>
<tr>
<td><strong>Total gross revenues</strong></td>
<td>$430,782</td>
<td>$453,949</td>
<td>$405,594</td>
<td>$388,934</td>
<td>$390,364</td>
</tr>
<tr>
<td><strong>Expenses (excluding depreciation and amortization)</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cost of purchased power</td>
<td>$275,013</td>
<td>$279,842</td>
<td>$245,442</td>
<td>$239,339</td>
<td>$236,208</td>
</tr>
<tr>
<td>Fuel and generation</td>
<td>23,643</td>
<td>21,986</td>
<td>21,884</td>
<td>21,921</td>
<td>26,981</td>
</tr>
<tr>
<td>Operations &amp; Maintenance</td>
<td>43,079</td>
<td>42,937</td>
<td>46,905</td>
<td>42,707</td>
<td>45,923</td>
</tr>
<tr>
<td>Right of Way fee</td>
<td>5,555</td>
<td>5,069</td>
<td>4,845</td>
<td>4,713</td>
<td>4,555</td>
</tr>
<tr>
<td><strong>Total expenses</strong></td>
<td>$347,290</td>
<td>$349,834</td>
<td>$319,076</td>
<td>$308,680</td>
<td>$313,667</td>
</tr>
<tr>
<td><strong>Net revenues(a)</strong></td>
<td>$  83,492</td>
<td>$104,115</td>
<td>$  86,518</td>
<td>$  80,254</td>
<td>$  76,697</td>
</tr>
<tr>
<td>Deposits to Renewal and Replacement Account</td>
<td>149</td>
<td>349</td>
<td>(142)</td>
<td>594</td>
<td>270</td>
</tr>
<tr>
<td><strong>Surplus Revenues(c)</strong></td>
<td>$  83,343</td>
<td>$103,766</td>
<td>$  86,660</td>
<td>$  79,660</td>
<td>$  76,427</td>
</tr>
<tr>
<td>Qualified Obligations purchase payments(d)(4)</td>
<td>33,212</td>
<td>43,916</td>
<td>43,863</td>
<td>40,234</td>
<td>39,371</td>
</tr>
<tr>
<td>Second Lien Qualified Obligations(e)(5)</td>
<td>8,417</td>
<td>8,415</td>
<td>8,416</td>
<td>8,416</td>
<td>8,412</td>
</tr>
<tr>
<td><strong>Net revenues after debt service payments</strong></td>
<td>$41,714</td>
<td>$51,435</td>
<td>$34,381</td>
<td>$31,010</td>
<td>$28,644</td>
</tr>
<tr>
<td><strong>Transfers (to) Anaheim General Fund</strong></td>
<td>(17,128)</td>
<td>(17,504)</td>
<td>(15,067)</td>
<td>(16,042)</td>
<td>(14,122)</td>
</tr>
<tr>
<td><strong>Transfers (to)/from other Anaheim funds</strong></td>
<td>297</td>
<td>59</td>
<td>(872)</td>
<td>2,153</td>
<td>1,276</td>
</tr>
<tr>
<td><strong>Balance for other purposes</strong></td>
<td>$ 24,883</td>
<td>$ 33,990</td>
<td>$ 18,442</td>
<td>$ 17,121</td>
<td>$ 15,798</td>
</tr>
<tr>
<td><strong>Qualified Obligation (incl. Second Lien)</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>debt service coverage (c/(d +e))</td>
<td>2.0x</td>
<td>2.0x</td>
<td>1.7x</td>
<td>1.6x</td>
<td>1.6x</td>
</tr>
</tbody>
</table>

---

(1) Other revenue was restated to exclude capital grants from operation revenue based on GASB 34. Other revenue includes transmission revenue, revenue from the sale of surplus natural gas, interest income and other miscellaneous revenue.

(2) Includes take-or-pay obligations with joint powers agencies.

(3) Fuel and generation includes all expenses associated with the operation of the Kraemer CT Plant and San Juan Unit 4.

(4) Qualified Obligations outstanding at June 30, 2014 include $92,130,000 Anaheim Public Financing Authority Revenue Bonds, Series 2012-A, $90,390,000 Anaheim Public Financing Authority Revenue Bonds, Series 2011-A, $65,350,000 Anaheim Public Financing Authority Revenue Bonds, Series 2009-A, $194,965,000 Anaheim Public Financing Authority Distribution System Revenue Bonds, Series 2007-A; $25,680,000 Anaheim Public Financing Authority Revenue Refunding Bonds, Series 2003-A; and $29,930,000 Anaheim Public Financing Authority Revenue Bonds, Series 1999. Decline in Qualified Obligations purchase payments in Fiscal Year 2014 from the prior Fiscal Year primarily due to the refinancing in July 2013 of then outstanding Anaheim Public Financing Authority Revenue Anticipation Notes of Anaheim which are payable from Surplus Revenues on a basis that is junior and subordinate to the payment of the Qualified Obligations and Second Lien Qualified Obligations. See “Electric System Indebtedness and Joint Powers Agency Obligations.”

(5) Second Lien Qualified Obligations outstanding at June 30, 2014 include $108,440,000 Anaheim Public Financing Authority Distribution System Revenue Bonds, Series 2004 (which were refunded in October 2014 with Qualified Obligations).

Source: Anaheim.
Transfers of Electric System funds to Anaheim’s General Fund are being made on a monthly basis. Under the Charter, annual transfers are limited to 4% of gross revenues of the Electric Revenue Fund for the prior fiscal year.

Under the Anaheim Charter and certain resolutions of the Anaheim City Council, revenues of the Anaheim Electric System are applied first to service the Anaheim Electric System’s Senior Electric Bonds, if any, and related reserves, then to operating and maintenance expenses and then to other obligations payable from gross revenues of the Anaheim Electric System.

The following Condensed Balance Sheet has been prepared by Anaheim based upon the audited financial statements of the Anaheim Electric System for the fiscal years shown.

City of Anaheim
Electric Utility Fund
Condensed Balance Sheet
($000)

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Investment in Utility Plants:</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Production</td>
<td>$123,622</td>
<td>$123,412</td>
<td>$119,144</td>
<td>$117,978</td>
<td>$115,477</td>
</tr>
<tr>
<td>Transmission</td>
<td>94,220</td>
<td>92,323</td>
<td>92,229</td>
<td>91,022</td>
<td>89,895</td>
</tr>
<tr>
<td>Distribution</td>
<td>877,903</td>
<td>851,842</td>
<td>805,703</td>
<td>780,122</td>
<td>725,878</td>
</tr>
<tr>
<td>General</td>
<td>127,752</td>
<td>112,045</td>
<td>109,346</td>
<td>107,919</td>
<td>104,714</td>
</tr>
<tr>
<td><strong>Gross utility plant</strong></td>
<td>1,223,497</td>
<td>1,179,622</td>
<td>1,126,422</td>
<td>1,097,041</td>
<td>1,035,964</td>
</tr>
<tr>
<td>Less–accumulated depreciation</td>
<td>(459,092)</td>
<td>(422,668)</td>
<td>(386,832)</td>
<td>(350,483)</td>
<td>(319,103)</td>
</tr>
<tr>
<td><strong>Net plant in service</strong></td>
<td>764,405</td>
<td>756,954</td>
<td>739,590</td>
<td>746,558</td>
<td>716,861</td>
</tr>
<tr>
<td>Land</td>
<td>35,671</td>
<td>35,671</td>
<td>35,671</td>
<td>35,671</td>
<td>35,671</td>
</tr>
<tr>
<td>Construction work in progress</td>
<td>55,001</td>
<td>34,814</td>
<td>46,201</td>
<td>35,498</td>
<td>40,508</td>
</tr>
<tr>
<td>Total utility plant</td>
<td>$855,077</td>
<td>$827,439</td>
<td>$821,462</td>
<td>$817,727</td>
<td>$793,040</td>
</tr>
<tr>
<td><strong>Production Costs</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Owned Generation(1)</td>
<td>$32,415</td>
<td>$30,848</td>
<td>$26,845</td>
<td>$31,149</td>
<td>$38,693</td>
</tr>
<tr>
<td>Purchased Power(2)</td>
<td>207,542</td>
<td>202,736</td>
<td>184,082</td>
<td>175,363</td>
<td>183,866</td>
</tr>
<tr>
<td>Total Production Costs</td>
<td>$239,957</td>
<td>$233,584</td>
<td>$210,927</td>
<td>$206,512</td>
<td>$222,559</td>
</tr>
<tr>
<td>Transmission-69 kV Circuit Miles(3)</td>
<td>86</td>
<td>87</td>
<td>86</td>
<td>90</td>
<td>80</td>
</tr>
<tr>
<td>Distribution Overhead Circuit Miles(3)</td>
<td>420</td>
<td>426</td>
<td>428</td>
<td>440</td>
<td>446</td>
</tr>
<tr>
<td>Underground Circuit Miles(3)</td>
<td>666</td>
<td>662</td>
<td>656</td>
<td>658</td>
<td>617</td>
</tr>
<tr>
<td><strong>Transformer Capacity (in kVA)</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>220 kV to 69 kV</td>
<td>1,808,000</td>
<td>1,808,000</td>
<td>1,808,000</td>
<td>1,808,000</td>
<td>1,808,000</td>
</tr>
<tr>
<td>69 kV to 12 kV</td>
<td>1,135,400</td>
<td>1,135,400</td>
<td>1,135,400</td>
<td>1,135,400</td>
<td>1,135,400</td>
</tr>
<tr>
<td>12 kV to Customer</td>
<td>1,561,515</td>
<td>1,551,572</td>
<td>1,545,500</td>
<td>1,557,040</td>
<td>1,559,932</td>
</tr>
</tbody>
</table>

(1) Information includes debt service on facilities during the fiscal period.
(2) Excludes transmission costs and gas sold.
(3) Transformer capacity changes reflect more up to date information derived from Anaheim’s geographic information system.
Source: Anaheim.
Electric System Indebtedness and Joint Powers Agency Obligations

**Direct Obligations.** As of December 31, 2014, Anaheim had outstanding $575,105,000 principal amount of long-term direct Electric System obligations under installment purchase agreements with the Anaheim Public Financing Authority (“Qualified Obligations”) payable from and secured by net revenues of the Electric System.

**Joint Powers Agency Obligations.** As previously discussed, Anaheim participates in or contracts with several joint powers agencies, including Intermountain Power Agency (“IPA”) and SCPPA. Obligations of Anaheim under the agreements with IPA and SCPPA constitute maintenance and operation expenses of Anaheim payable prior to any of the payments required to be made with respect to Anaheim’s outstanding direct electric system obligations (other than Anaheim’s outstanding Senior Electric Bonds, if any). Agreements between Anaheim and IPA and Anaheim and SCPPA (other than the agreement relating to SCPPA’s Prepaid Natural Gas Project bonds) are on a “take-or-pay” basis, which requires payments to be made whether or not applicable projects are completed or operable, or whether output from such projects is suspended, interrupted or terminated. All of these agreements (other than the agreements relating to SCPPA’s Prepaid Natural Gas Project bonds, the Natural Gas Reserves bonds, and the Canyon Power Project bonds) contain “step up” provisions obligating Anaheim to pay a share of the obligations of a defaulting participant. Anaheim’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.

<table>
<thead>
<tr>
<th>Outstanding Debt of Joint Powers Agencies and Anaheim Share</th>
<th>As of December 31, 2014</th>
</tr>
</thead>
<tbody>
<tr>
<td>Principal Amount of Outstanding Debt</td>
<td>Anaheim’s Participation(1)</td>
</tr>
<tr>
<td>Intermountain Power Agency</td>
<td></td>
</tr>
<tr>
<td>Intermountain Power Project(3)</td>
<td>$1,530,540,000</td>
</tr>
<tr>
<td>Southern California Public Power Authority</td>
<td></td>
</tr>
<tr>
<td>Southern Transmission System</td>
<td>$ 657,630,000</td>
</tr>
<tr>
<td>Hoover Dam Uprating</td>
<td>6,095,000</td>
</tr>
<tr>
<td>Magnolia Power Project(4)</td>
<td>314,630,000</td>
</tr>
<tr>
<td>Mead-Phoenix Transmission</td>
<td>33,175,000</td>
</tr>
<tr>
<td>Mead-Adelanto Transmission</td>
<td>108,785,000</td>
</tr>
<tr>
<td>Prepaid Natural Gas Project</td>
<td>309,615,000</td>
</tr>
<tr>
<td>Natural Gas Reserves(5)</td>
<td>47,865,000</td>
</tr>
<tr>
<td>Canyon Power Project</td>
<td>301,470,000</td>
</tr>
<tr>
<td>Total</td>
<td>$3,309,805,000</td>
</tr>
</tbody>
</table>

(1) Obligation is subject to increase upon default of another Project Participant (other than with respect to SCPPA’s Natural Gas Prepaid bonds, the Natural Gas Reserves bonds and the Canyon Power Project bonds).

(2) Excludes interest on the debt.

(3) Includes bonds, commercial paper, and subordinate notes.

(4) Excludes bonds relating solely to City of Cerritos.

(5) Not a “take-or-pay” obligation; Anaheim must pay for contracted natural gas only to the extent delivered.

Source: Anaheim.

For the fiscal year ended June 30, 2015, Anaheim’s payments of debt service on its joint powers agency obligations is expected to aggregate approximately $90.7 million. Annual debt service on Anaheim’s joint powers agency obligations is expected to decrease from the level and decline to approximately $19.5 million in fiscal year 2041. This projection assumes no future debt issuances and further assumes that the annual interest rate on unhedged variable rate joint powers agency debt obligations (i.e., joint powers agency obligations not otherwise fixed through interest rate swap agreements) will be 3.0%. As of December 31, 2014, approximately 2.0% of the joint powers agency
obligation debt service was unhedged variable rate debt, including outstanding commercial paper. Unreimbursed draws under liquidity arrangements supporting joint powers agency variable rate debt obligations bear interest at a maximum rate substantially in excess of the assumed rates stated above.

Financial Condition

Total gross revenues for the fiscal year ended June 30, 2014 of $430.8 million represent a $23.2 million decrease from the prior fiscal year, which is mainly due to a $14.5 million decrease in the recognition of revenues from the RSA and a $12.4 million decrease in retail electric revenues.

$26.5 million of RSA revenues were recognized in the fiscal year ended June 30, 2014 in order to maintain a sound debt service coverage ratio for the Electric Utility. The decrease of $14.5 million from the prior fiscal year was due to $3.2 million in lower purchased power, fuel and generation costs coupled with $10.7 million in reduced debt service obligations compared to the prior fiscal year. The Public Utilities Department was able to reduce its RSA revenues recognized and still maintain a sound debt service coverage ratio of 2.0x.

The $12.4 million (3.8%) decrease in retail sales revenues was due to lower sales volumes resulting from cooler weather and a continued investment in conservation and efficiency measures during the fiscal year ended June 30, 2014.

Total operating expenses of $347.3 million for the fiscal year ended June 30, 2014 represent a small decrease of $2.5 million (less than 1.0%) from the prior fiscal year total operating expenses of $349.8 million. The $2.5 million decrease in expenses was mainly due to a $3.1 million decline in power, fuel and generation costs. This decrease in power related costs was due to a concerted effort to source and procure renewable power resources and the least possible cost to ensure continued compliance with the State of California’s Renewable Power Supply requirements.

Labor Relations

The Anaheim Public Utilities Department has a total of 352 full-time and 42 part-time authorized positions. Of these positions, 158 full-time employees and 16 part-time employees are represented by the International Brotherhood of Electrical Workers (“IBEW”) Local 47. In addition to the IBEW, the Anaheim Municipal Employees Association (“AMEA”) represents 24 full-time employees of the Anaheim Public Utilities Department. There are no part-time employees represented by AMEA. Anaheim has reached agreements with IBEW and AMEA to extend their memoranda of understanding through January 2, 2017 and January 4, 2016, respectively. Anaheim has not experienced any strike, work stoppage or other labor action by the Anaheim Public Utilities Department’s employees in the last five years.

Retirement Programs

All permanent employees of Anaheim are covered under the California Public Employees’ Retirement System (“CalPERS”), a public employee, defined benefit pension plan. CalPERS issues a separate, publicly available financial report that includes financial statements and required supplemental information of participating public entities within the State of California. Copies of the CalPERS annual financial report may be obtained from the CalPERS Executive Office, Lincoln Plaza Complex, 400 Q Street, Sacramento, CA 95811 or at www.calpers.ca.gov.

For both fiscal years ended June 30, 2014 and 2013, as a condition of participation in the plan, employees were required to contribute 8% of their annual covered salary to CalPERS. Anaheim pays 7% of the employees’ required contributions and the employees pay the remaining 1%. For management employees hired after January 10, 2012, the entire 8% is paid by employees. Management and IBEW
employees hired on and after January 1, 2013 and who have no prior membership in any California public retirement system are required to contribute the employee rate of 6.75% of their annual covered salary to CalPERS. The entire 6.75% is paid by such employees. Anaheim is required to contribute the remaining amounts necessary to fund CalPERS, using the actuarial basis recommended by the CalPERS actuaries and actuarial consultants and adopted by the CalPERS Board of Administration. The Electric System is allocated its portion of the city’s required contribution, as determined by CalPERS actuaries. This allocation is based on eligible employee wages.

The Electric System contributed 100% of its allocated required contributions of $7,164,000, $7,104,000 and $6,700,000 to CalPERS for the fiscal years ended June 30, 2014, 2013, and 2012, respectively.

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

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

In all cases, eligible retirees may participate in any health plan made available to active Anaheim employees. Anaheim has several plans with different contribution levels and benefit provisions. Anaheim contributions vary up to 100% of annual premium cost, depending on the employee’s Medicare eligibility, year of hire, age and employee group. At June 30, 2014, 1,299 retirees or surviving spouses met the various eligibility requirements and were receiving benefits.

Anaheim’s contributions toward the cost of its OPEB program are generally advance funded on an actuarial basis to a dedicated reserve, but annual contributions are not required. During fiscal year 2013-14, Anaheim’s contribution to the post-employment medical plan was $10.145 million. Governmental Accounting Standards Board Statement No. 45 has required Anaheim to account for and disclose its OPEB liability since the fiscal year ended June 30, 2009.

The Electric System does not separately account for its allocable portion of the cost of pension and OPEB benefits funded, the actuarially computed present value of vested and nonvested accumulated plan benefits, the related assumed rates of return used, and the actuarially computed value of vested benefits over the related pension and OPEB fund assets.
Insurance

The Electric Utility participates in Anaheim’s self-insured workers’ compensation and general liability program. The liability for such claims, including claims incurred but not reported, is transferred to Anaheim in consideration of self-insurance premiums paid by the Electric Utility. Premiums for workers’ compensation and general liability programs are charged to the Electric Utility by Anaheim based on various allocation methods that include actual cost, trends in claims experience, exposure base, and number of participants. Premiums charged and paid were $1,603,000 and $1,459,000 for the years ended June 30, 2014 and June 30, 2013, respectively.

At June 30, 2014, Anaheim was fully funded for self-insured workers’ compensation and general liability claims (self-insured retention levels of $750 per occurrence for workers’ compensation claims and $1,000 per occurrence for general liability claims). Above these self-insured retention levels, Anaheim’s potential liability is covered through various commercial insurance and intergovernmental risk pooling programs. Settled claims have not exceeded total insurance coverage in any of the past three years, nor does management believe that there are any pending claims that will exceed total insurance coverage.

Litigation

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

[Remainder of page intentionally left blank]
CITY OF RIVERSIDE

The following is certain information concerning the City of Riverside ("Riverside" or the "City") and its Public Utilities Department (the "Riverside Public Utilities Department") and such Department’s electric utility (the "Riverside Electric System"), prepared by Riverside for inclusion herein. This information does not purport to cover all aspects of the Riverside Electric System’s business, operations and financial position. A copy of the most recent annual report of the Riverside Electric System may be obtained from the Assistant General Manager, Finance and Administration, Riverside Public Utilities Department, 3750 University Avenue, third floor, Riverside, California 92501, and is also available on the Riverside Public Utilities Department’s website at www.riversidepublicutilities.com. Information on such website is not incorporated into this document.

General

The Riverside Electric System operates as a vertically integrated utility providing service to virtually all electric consumers within the city limits of Riverside, which encompasses 81.5 square miles. The Riverside Electric System’s power supply requirements are met through:

(i) purchases of power under long-term power sales agreements with Bonneville Power Administration ("BPA");

(ii) the City’s internal generation consisting of 40 MW, simple cycle, combustion turbines ("Springs Generating Project") and the City’s four unit, 196 MW, power plant (Riverside Energy Resource Center) Units 1, 2, 3 and 4;

(iii) the City’s acquisition of the combined-cycle Clearwater Cogeneration Facility located in Corona, California (29.5 MW);

(iv) entitlements in the Intermountain Power Project ("IPP") Generating Station, and through its participation in the Southern California Public Power Authority (the "Authority"), the Authority’s Palo Verde Nuclear Generating Station Project and Hoover Uprating Project;

(v) contracts for renewable energy;

(vi) purchases of firm energy from various western utilities when it is available at an economical price or when needed to satisfy periods of peak demand; and

(vii) energy purchases through the California Independent System Operator (the “CAISO”) centralized markets.

The Riverside Electric System provides service throughout the City of Riverside to domestic, commercial, industrial, agricultural, municipal and other customers. For the fiscal year ended June 30, 2014, the number of customers of the Riverside Electric System was 108,358 and the total megawatt hours ("MWh") generated and purchased were 2,279,500.

History of the Electric System

Riverside was a pioneer in the transmission and distribution of electric power. The municipal electric system, which was constructed in 1895, was among the first of eight such municipally-owned systems in the State of California prior to the turn of the century. The Riverside electric utility had been fundamentally a sub-transmission and distribution system, although Riverside did generate part of its own power from 1900 to 1924. Power was purchased exclusively from Southern California Edison Company
(“Edison”) from 1950 to May 1976. At that time, Riverside began receiving non-firm energy purchased from the Nevada Power Company, which was delivered to Riverside by Edison. Since that time, Riverside has developed a number of other power supply resources, including the acquisition and construction of local generation assets, participation in joint powers agency projects and long and short-term power purchases with a variety of providers, as reflected above.

Management

Under the provision of the California Constitution and Article XII of the Riverside City Charter, Riverside owns and operates both electrical and water public utility services for its residents. The Riverside Public Utilities Department exercises jurisdiction over the electric and water utilities owned, controlled and operated by Riverside under the management and control of the Riverside City Manager, subject to the powers and duties vested in the Riverside Board of Public Utilities (the “Riverside Board”), and is supervised by the Public Utilities General Manager who is responsible for design, construction, maintenance and operation of the electric and water utilities. The Riverside Board, created by Article XII, Section 1201 of the Riverside City Charter, consists of nine members appointed by the Riverside City Council. The Riverside Board participates in, among other things: (i) the annual budget process, (ii) the acquisition of significant equipment, materials, and supplies, (iii) the acquisition, construction, improvement, or diminution of any part of the City’s public utility system, (iv) appropriations for capital expenditures, (v) the establishment of water and electric rates, and (vi) the selection of the Public Utilities General Manager.

Girish Balachandran was appointed the Public Utilities General Manager for the City of Riverside in January 2014. He received his Bachelor of Engineering degree from Anna University in India, and his Master of Science degree in Electrical Engineering from the University of California, Los Angeles. He has nearly 23 years of experience in municipal government, including previously serving as General Manager of Alameda Municipal Power since 2007. Prior to his tenure in Alameda, he served in a variety of capacities with the City of Palo Alto Utilities, including Assistant Director of Utilities, Resource Management; Manager, Supply Resources; and Resource Planner. He started his career as an analyst with Pasadena Water and Power.

Electric System Facilities

Generation

City-owned generating facilities include the City’s Springs Generating Project, the Riverside Energy Resource Center (“RERC”), and baseload generation ownership in the Clearwater Cogeneration Facility (“Clearwater”).

The Springs Generating Project (which began commercial operations in 2002) consists of four natural gas, simple cycle, turbine generators, each with a capacity of 10 MW (for a total of 40 MW). The Springs Generating Project is used primarily to serve the Electric System’s native load during periods of super peak power demand in the City. These facilities are also available to be used if normal operations of the Electric System are disrupted, and will provide essential emergency services within the City, such as hospital care, traffic control and police and fire dispatching.

RERC Units 1 and 2 are natural gas-fired, simple-cycle plants located in the City, consisting of two General Electric LM 6000 SPRINT combustion turbines, nominally rated at 49 MW each (net power at site conditions) and related sub-transmission lines. The total construction costs of RERC Units 1 and 2 was $81.6 million. The units were completed in June 2006 and have a combined operating capacity of 98 MW with emission levels that allow for approximately 1,200 hours of run time per unit, per year. RERC Units 3 and 4 are of the same make, model and operating characteristics as RERC Units 1 and 2 and
achieved commercial operation on April 1, 2011. The total estimated cost for RERC Units 3 and 4 was $112.5 million, the majority of which was financed by electric revenue bonds issued by the City in 2008. RERC Units 3 and 4 have a combined operating capacity of 98 MW with emission levels that allow for approximately 150 hours of run time per unit, per month. All four RERC Units serve the Electric System’s native load when economically feasible or during periods of peak power demand in the City, enhance reliability and service delivery to customers and provide energy and ancillary services in the CAISO markets.

The City entered into the Clearwater Asset Purchase/Sale Agreement on March 3, 2010, for the City’s purchase of Clearwater from the City of Corona, California (“Corona”). Clearwater consists of a single, GE LM2500, combustion turbine generator operating in combined cycle with one RENTECH heat recovery steam generator, and one SHIN NIPPON steam turbine generator. The gross plant output of Clearwater is 29.5 MW. The construction of Clearwater was financed by Corona through the issuance of two series of certificates of participation (“COPs”). Riverside agreed to pay annual payments generally consistent with debt service on Corona’s COPs until the first call date of each series, upon which the City would pay Corona the then outstanding principal amount of the COPs. The ownership of Clearwater transferred from Corona to Riverside effective September 1, 2010. On July 25, 2013, the City issued electric revenue bonds to prepay the outstanding obligation to the City of Corona. Clearwater has been included in Riverside’s resource portfolio and is expected to evolve into a baseload resource over time. The necessary air quality permits for the City’s intended operation of Clearwater are in place. Clearwater will also be utilized by the City to meet the local resource adequacy requirements of the CAISO.

The City has a 1.79% undivided ownership interest in Units 2 and 3 of San Onofre Nuclear Generating Station (“SONGS”); however, on June 7, 2013, Edison, as principal owner and operating agent, announced its plan to retire Units 2 and 3 of the SONGS permanently. Consequently, the Units are no longer a power resource for the Electric System, but the City continues to be responsible for operating costs, as well as costs associated with the Units’ shutdown and decommissioning.

During the outage, the City had procured replacement power to serve its customers’ requirements. These costs were in addition to the usual approximate $11.5 million in operating and maintenance expenses paid annually during normal operations. Replacement power costs incurred by the City as a result of the outage (commencing on January 31, 2012 for Unit 3 and March 5, 2012 for Unit 2) through June 30, 2013 were approximately $13.2 million and are reflected as regulatory assets on the Statements of Net Position. During fiscal year 2014, the City paid for its share of ongoing operating costs and replacement power related to SONGS from current rate revenue.

Subtransmission and Distribution

Power is supplied to Riverside through seven separate, 69,000-volt, sub-transmission lines owned and operated by Edison. These lines are used for the sole purpose of delivering electric energy from Edison’s Vista Substation to the northerly limits of Riverside, at which connection points are made to the Riverside-owned and operated, 69,000-volt, sub-transmission system.

As of June 30, 2014, Riverside had 98.6 circuit miles of sub-transmission and 1,327 circuit miles of distribution lines, of which approximately 814 circuit miles are underground. The underground lines are primarily in commercial and new residential areas. There are 14 substations, with a combined capacity of 1,032 million volt-amperes (“MVA”). Riverside is currently undertaking the Riverside Transmission Reliability Project (“RTRP”), which includes the construction of a 230-69 kV, transmission substation, which will provide a second point of interconnection to the California transmission grid, and the addition of new 69 kV transmission lines to transmit power from the new substation and distribute energy to Riverside’s local distribution substations. The City Council certified the Environmental Impact Report for RTRP, as required by California Environmental Quality Act, and approved the project on
February 5, 2013. On March 6, 2013, the City of Jurupa Valley filed a lawsuit entitled *City of Jurupa Valley v. City of Riverside* (RIC 1302675) challenging the approval and asking the court to block the project. A hearing was held on April 11, 2014, and on May 1, 2014, the court issued judgment in favor of the City and upheld the City’s decision regarding the EIR. The court denied City of Jurupa Valley’s petition for a writ of mandate. The City of Jurupa Valley has appealed this decision. No date has been set for the hearing of the appeal. The costs of the RTRP have been partially financed by electric revenue bonds issued by the City in 2008 and 2010. On December 4, 2007, the City added a reliability charge to its electric rates to assist with funding the City’s portion of the cost of RTRP.

**Power Supply**

As more fully described herein, the electricity supplied to Riverside consists of: (a) power generated within the City of Riverside from its City-owned generation resources, the Springs Generating Project, RERC, and Clearwater; (b) the City’s entitlements in certain joint powers agency projects, the IPP Generating Station, and the Authority’s Palo Verde Nuclear Generating Station Project (“PVNGS”), and Hoover Uprating Project; (c) long-term contracts of firm purchases from BPA; (d) long-term renewable power purchase agreements for wind energy from Wintec-Pacific Solar, LLC and WKN Wagner, LLC, and geothermal energy from Salton Sea Power LLC (“Salton Sea”) (see “Renewable Resources” below); and (e) firm energy purchases from other entities and energy purchased through the CAISO’s centralized markets. For the fiscal year ended June 30, 2014, the overall average net cost of generation and transmission was 7.7 cents per kilowatt-hour (“kWh”).

During the fiscal year ended June 30, 2014, the Riverside Electric System generated and purchased a total of 2,279,500 MWh of electricity for delivery to customers throughout Riverside. The following table sets forth the amounts in MWh and percentages of electricity obtained by Riverside during the fiscal year ended June 30, 2014.

<table>
<thead>
<tr>
<th>Riverside Electric System</th>
<th>MWh</th>
<th>Percentage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fiscal Year Ended June 30, 2014</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Resources</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>IPP Generating Station..................................................</td>
<td>802,100</td>
<td>35.2%</td>
</tr>
<tr>
<td>Firm Contracts ....................................................................</td>
<td>899,200</td>
<td>39.4%</td>
</tr>
<tr>
<td>NVG .................................................................</td>
<td>99,900</td>
<td>4.4%</td>
</tr>
<tr>
<td>Hoover Uprating Project.................................................</td>
<td>33,200</td>
<td>1.5%</td>
</tr>
<tr>
<td>Springs/RERC/Clearwater..................................................</td>
<td>86,300</td>
<td>3.8%</td>
</tr>
<tr>
<td>Renewable Resources ......................................................</td>
<td>423,800</td>
<td>18.6%</td>
</tr>
<tr>
<td>Net Exchange In/(Out).....................................................</td>
<td>(65,000)</td>
<td>(2.9)%</td>
</tr>
<tr>
<td><strong>Total</strong> ......................................................................</td>
<td>2,279,500</td>
<td>100.0%</td>
</tr>
</tbody>
</table>

(1) Includes native load, losses, and wholesale power sales.

The system peak for the fiscal year ended June 30, 2014 was 577.9 MW. The historic system peak of 604.4 MW was set on August 31, 2007. The following table sets forth, in MWh of electricity, the total purchases of power and Riverside Electric System peak demand during the periods shown.
Riverside Electric System
Total Energy Generated and Purchased and Peak Demand

<table>
<thead>
<tr>
<th></th>
<th>Fiscal Year Ended June 30,</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2014</td>
</tr>
<tr>
<td>From City’s Own Generation (MWh)</td>
<td>91,500(3)</td>
</tr>
<tr>
<td>From Other Sources (MWh)</td>
<td>2,188,000</td>
</tr>
<tr>
<td>System Total (MWh)(1)</td>
<td>2,279,500</td>
</tr>
<tr>
<td>System Peak Demand (MW)</td>
<td>577.9</td>
</tr>
<tr>
<td>System Native Load (MW)</td>
<td>2,148,000</td>
</tr>
</tbody>
</table>

(1) Before system losses.
(2) Increase primarily due to warmer weather patterns.
(3) Decrease in internal generation due to the prior outage and subsequent retirement of SONGS Units 2 and 3.

Renewable Resources

In an effort to increase the share of renewables in the City’s power portfolio, the City entered into power purchase agreements (“PPAs”) with various entities described below on a “take-and-pay” basis. The contracts in the following tables were executed as part of compliance with the State-mandated Renewable Portfolio Standard target. See “State and Federal Legislation” below.

Long-term renewable PPAs in operation:

<table>
<thead>
<tr>
<th>Supplier</th>
<th>Type</th>
<th>Maximum Contract(1)</th>
<th>Contract Expiration</th>
</tr>
</thead>
<tbody>
<tr>
<td>Salton Sea Power LLC</td>
<td>Geothermal</td>
<td>46.0 MW</td>
<td>05/31/2020</td>
</tr>
<tr>
<td>Wintec</td>
<td>Wind</td>
<td>1.3 MW</td>
<td>12/30/2018</td>
</tr>
<tr>
<td>WKN Wagner</td>
<td>Wind</td>
<td>6.0 MW</td>
<td>12/22/2032</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td>53.3 MW</td>
<td></td>
</tr>
</tbody>
</table>

Long-term renewable PPAs with expected delivery:

<table>
<thead>
<tr>
<th>Supplier</th>
<th>Type</th>
<th>Maximum Contract(1)</th>
<th>Expected Delivery</th>
<th>Energy Delivery No Later Than</th>
<th>Contract Term in Years</th>
</tr>
</thead>
<tbody>
<tr>
<td>CalEnergy</td>
<td>Geothermal</td>
<td>86.0 MW</td>
<td>02/11/2016</td>
<td>02/11/2016</td>
<td>25</td>
</tr>
<tr>
<td>AP North Lake</td>
<td>Photovoltaic</td>
<td>20.0 MW</td>
<td>06/30/2015</td>
<td>12/31/2015</td>
<td>25</td>
</tr>
<tr>
<td>FTP Solar</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Summer Solar</td>
<td>Photovoltaic</td>
<td>10.0 MW</td>
<td>06/30/2016</td>
<td>12/31/2016</td>
<td>25</td>
</tr>
<tr>
<td>Antelope Big Sky Ranch</td>
<td>Photovoltaic</td>
<td>10.0 MW</td>
<td>06/30/2016</td>
<td>12/31/2016</td>
<td>25</td>
</tr>
<tr>
<td>First Solar</td>
<td>Photovoltaic</td>
<td>14.0 MW</td>
<td>12/31/2015</td>
<td>06/30/2016</td>
<td>20</td>
</tr>
<tr>
<td>Recurrent Clearwater</td>
<td>Photovoltaic</td>
<td>14.9 MW</td>
<td>06/30/2016</td>
<td>12/31/2015</td>
<td>20</td>
</tr>
<tr>
<td>Dominion Columbia Two</td>
<td>Photovoltaic</td>
<td>11.1 MW</td>
<td>12/31/2014(2)</td>
<td>12/31/2015</td>
<td>20</td>
</tr>
<tr>
<td>Cabazon Wind</td>
<td>Wind</td>
<td>39.0 MW</td>
<td>01/01/2015</td>
<td>12/31/2015</td>
<td>10</td>
</tr>
<tr>
<td>Solar Star</td>
<td>Photovoltaic</td>
<td>7.3 MW</td>
<td>09/30/2015</td>
<td>12/31/2015</td>
<td>25</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td>212.3 MW</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

(1) All contracts are contingent on energy production from specific related generating facilities. The City has no commitment to pay any amounts except for energy produced on a monthly basis from these facilities.
(2) Commenced commercial operation in December 2014 as scheduled.
On May 20, 2003, the City and Salton Sea entered into a ten-year PPA for 20 MW of geothermal energy. On August 23, 2005, the City Council approved an amendment to the PPA which increases the amount of renewable energy available to the City from 20 MW to 46 MW effective June 1, 2009 through May 31, 2020.

On May 14, 2013, the City Council approved a new 25-year PPA with CalEnergy, the parent of Salton Sea, for additional renewable geothermal power. The PPA provides power from a portfolio of ten geothermal generating units, instead of a single generating unit, with an increasing amount of delivery starting with 20 MW in 2016 and increasing to 40 MW in 2019 and 86 MW in 2020. The PPA is expected to provide 7.5%, 15% and 30% of the City’s total power demand in 2016, 2019, and 2020, respectively. The price under the agreement will be $72.85 per MWh in calendar year 2016 and escalate at 1.5% annually for the remaining term of the agreement. Similar to other renewable PPAs, the City is only obligated for purchases of energy delivered to the City.

Concurrently, the pricing under the Salton Sea PPA has been amended to conform to pricing in the new PPA with CalEnergy through the remaining term of the Salton Sea PPA. The pricing under the Salton Sea PPA increased by approximately $7.57 per MWh, commencing July 1, 2013 to $69.66 per MWh, with an escalation of 1.5% annually thereafter, reflecting the exchange of benefits for a substantial lower pricing under the new PPA. The cost increase under the Salton Sea PPA is approximately $2.7 million per year for the agreement’s remaining term. This increase in price for fiscal year 2014 is recorded in the Statements of Net Position as unamortized purchased power in the amount of $2.0 million, to be amortized over the term of the CalEnergy PPA.

On November 10, 2006, the City entered into a second renewable PPA with Wintec Energy, Ltd (“Wintec”) for wind generation capacity of up to 8.0 MW on their proposed Wintec Facility II Wind Turbine Project. The contract term is for 15 years, expiring November 10, 2021. The developer encountered challenges in finding suitable wind turbines to complete the project. Due to the delay of the proposed Wintec Facility II Wind Turbine Project, on February 7, 2012, Wintec entered into an assignment agreement with WKN Wagner, LLC (“WKN”) for the purpose of assigning to WKN all of Wintec’s right, title, and interest in the renewable PPA dated November 10, 2006. The City agreed to the assignment and entered into a new PPA with WKN under the same commercial terms and conditions as in the original agreement with Wintec, except that the term has been extended to 20 years, instead of 15. WKN completed the project development timely, and the project became commercially operational on December 22, 2012 and is expected to contribute 1% of the City’s retail load requirements at a levelized cost of $73 per MWh. The City does not expect to receive more than 1.3 MW from Wintec per the original contract which expires in December 2018.

On October 16, 2012, the City entered into a 25-year PPA with AP North Lake, LLC (“AP North”) for 20 MW of solar photovoltaic energy generated by a new facility located in the City of Hemet, California. The AP North project is expected to become commercially operational by June 30, 2015, but in no event later than December 31, 2015. The project is expected to generate 55,000 MWh of renewable energy per year at a levelized cost of $95 per MWh for the term of the PPA.

On January 8, 2013, the City entered into two 25-year PPAs through the Authority for a combined total of 20 MW of solar photovoltaic energy generated by two facilities to be built by Silverado Power, which was later acquired by FTP Solar LLC, in the City of Lancaster, California. The two projects are referred to as Antelope Big Sky Ranch and Summer Solar, each rated at 20 MW. The City will have a 50% share of the output from each project through the Authority. The projects were expected to become commercially operational by January 1, 2015, but in no event later than December 31, 2015. The City’s share from the two projects is 55,000 MWh of renewable energy per year. On April 1, 2014, the City Council approved the first amendment to the PPAs, which postponed the outside commercial operation date for each project from December 31, 2015 to December 31, 2016, with the most significant
change being a reduction in a price for energy and environmental attributes from $95.30 per MWh to $71.25 per MWh over the term of the agreement.

On September 19, 2013, the City entered into a 20-year PPA through the Authority for 14 MW of solar photovoltaic energy generated by a facility to be built by First Solar in Kern County, California. The project is referred to as the Kingbird B Solar Photovoltaic Project, with a nameplate capacity of 20 MW. The City will have a 70% share of the output from the project through the Authority. The project is expected to become commercially operational at the end of 2015, but no later than June 30, 2016. The City’s share from the project is approximately 35,000 MWh of renewable energy per year with an all-in price for energy, capacity and environmental attributes of $68.75 per MWh over the term of the agreement.

On September 19, 2013, the City entered into two 20-year PPAs through the Authority for a combined 26 MW of solar photovoltaic energy generated by two facilities to be built by Recurrent Energy in Kern County, California. The two projects being developed are referred to as Clearwater and Columbia Two Solar Photovoltaic Projects, with a nameplate capacity of 20 MW and 15 MW, respectively. The City will have a 74.29% share of the output from the projects through the Authority. The City’s share from the two projects is approximately 65,000 MWh of renewable energy per year with an all-in price for energy, capacity and environmental attributes of $69.98 per MWh over the term of the agreements. Both projects were originally expected to become commercially operational at the end of 2014. However, the Clearwater project has encountered significant delays. See “SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY – Other Activities of the Authority” in the front part of this Official Statement. The Columbia Two project development commenced commercial operation in December 2014, as scheduled. On March 14, 2014, a Consent and Agreement was entered into by the Authority consenting to the transfer of ownership of the Columbia Two project to Dominion Solar. Upon completion of the permitting process by Recurrent Energy, a similar transfer to Dominion Solar is expected for the Clearwater project.

On December 6, 2013, the City and FPL Energy Cabazon Wind, LLC (“Cabazon Wind”) entered into a 10-year PPA for 39 MW of renewable wind energy from the Cabazon Wind Energy Center near Cabazon, California. Cabazon Wind is an existing renewable resource that has been in commercial operation since 1999. Edison is currently purchasing the output of the facility through December 2014. At the expiration of Edison’s contract, the project will need to enter into new interconnection and generation agreements with the CAISO and Edison, and the developer is on schedule to implement the transition to the City. Delivery under the PPA commenced on December 22, 2014. The project is expected to generate 71,200 MWh of renewable energy per year with an all-in price for energy, capacity and environmental attributes of $59.30 per MWh over the term of the agreement.

On March 11, 2014, the City and Solar Star California XXXI, LLC (“Solar Star”) entered into a 25-year PPA for 7.3 MW of solar photovoltaic energy generated by a facility to be built on the City-owned Tequesquite Landfill. The project is expected to become commercially operational by June 1, 2015 and is expected to generate approximately 15,000 MWh of renewable energy per year. On September 5, 2014, SunPower, the parent company of Solar Star, requested an extension of the date of commercial operation to September 30, 2015. The all-in price for energy, capacity and environmental attributes is $81.30 per MWh escalating at 1.5% annually.

**California Independent System Operator**

Riverside serves as its own Scheduling Coordinator with the CAISO and serves as the scheduling agent, under separate Utility Service Agreements, for the Cities of Banning, Azusa and Rancho Cucamonga. Services under the agreements include resource planning, day-ahead and real time scheduling of power from various sources, after-the-fact validation and settlement of transactions, and
billing and payments. Banning, Azusa, and Rancho Cucamonga share the estimated staff and business systems costs attributable to the specific services the City provides. These costs, approximately $900,000, are negotiated annually to reflect changes in the City’s cost of supplying these services.

On July 10, 2002, Riverside notified the CAISO of its intent to become a Participating Transmission Owner (“PTO”) by turning over operational control of Riverside’s transmission entitlements (the “CAISO-Transferred Entitlements”) to the CAISO effective January 1, 2003. In November 2002, Riverside executed the Transmission Control Agreement (“TCA”) between the CAISO and the PTOs.

Certain of Riverside’s CAISO-Transferred Entitlements relate to transmission facilities, including the Southern Transmission System, that were financed by the Authority utilizing tax-exempt bonds (the “Authority’s Bonds”). Riverside executed certain transmission service contracts with the Authority that prohibit Riverside from taking any action that would adversely affect the tax-exempt status of the Authority’s Bonds. If Riverside were to be found to have breached such contractual obligation, Riverside could be subjected to significant financial liability. The TCA executed by Riverside and submitted by the CAISO on November 19, 2002 for approval by the Federal Energy Regulatory Commission (“FERC”) contained certain withdrawal provisions which Riverside believes will protect the tax-exempt status of the Authority’s Bonds and satisfy Riverside’s contractual obligation to the Authority under its transmission service contracts.

On January 1, 2003, Riverside became a PTO with the CAISO, entitling Riverside to receive compensation for the use of its transmission entitlements committed to the CAISO’s operational control. The compensation is based upon Riverside’s Transmission Revenue Requirement (“TRR”) as approved by FERC. Included in Riverside’s TRR are all costs associated with Riverside’s participation in the Authority’s transmission projects (the Southern Transmission System and the Mead-Adelanto and Mead-Phoenix transmission projects). Riverside now obtains all of its transmission entitlements from the CAISO.

Since becoming a PTO with the CAISO, the City has filed three TRRs with FERC. Under the terms of the most recent agreement, the City’s base TRR is $29,400,000 which is adjusted annually for (among other things) automatic pass throughs of certain costs approved by FERC and Riverside’s actual retail load. For fiscal year ended June 30, 2014, Riverside collected $32,630,000 in TRR revenue.

Customers and Energy Sales

The following tables set forth the number of meters as of the fiscal year end and total energy sold during the periods presented.

<table>
<thead>
<tr>
<th>Riverside Electric System</th>
<th>Number of Meters</th>
<th>Fiscal Year Ended June 30,</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2014</td>
<td>2013</td>
</tr>
<tr>
<td>Domestic....................</td>
<td>96,820</td>
<td>96,207</td>
</tr>
<tr>
<td>Commercial ..................</td>
<td>10,558</td>
<td>10,337</td>
</tr>
<tr>
<td>Industrial .................</td>
<td>898</td>
<td>894</td>
</tr>
<tr>
<td>Other .......................</td>
<td>82</td>
<td>87</td>
</tr>
<tr>
<td>Total – all classes........</td>
<td>108,358</td>
<td>107,525</td>
</tr>
</tbody>
</table>
## Riverside Electric System

**Energy Sold**

(Millions of kWh)

<table>
<thead>
<tr>
<th></th>
<th>2014</th>
<th>2013</th>
<th>2012</th>
<th>2011</th>
<th>2010</th>
</tr>
</thead>
<tbody>
<tr>
<td>Domestic</td>
<td>700</td>
<td>726</td>
<td>688</td>
<td>666</td>
<td>701</td>
</tr>
<tr>
<td>Commercial</td>
<td>421</td>
<td>419</td>
<td>413</td>
<td>400</td>
<td>406</td>
</tr>
<tr>
<td>Industrial</td>
<td>997</td>
<td>1003</td>
<td>969</td>
<td>912</td>
<td>906</td>
</tr>
<tr>
<td>Wholesale Sales</td>
<td>4</td>
<td>14</td>
<td>2</td>
<td>7</td>
<td>44</td>
</tr>
<tr>
<td>Other</td>
<td>30</td>
<td>31</td>
<td>31</td>
<td>31</td>
<td>32</td>
</tr>
<tr>
<td>Total kWh Sold (^{(1)(2)})</td>
<td>2,152</td>
<td>2,193</td>
<td>2,103</td>
<td>2,016</td>
<td>2,089</td>
</tr>
</tbody>
</table>

\(^{(1)}\) Effective April 1, 2009, with the launch of CAISO’s market redesign and technology update (“MRTU”), entities are no longer required to submit a balanced schedule (e.g., load equal to resources), as the CAISO as the Balancing Area Authority will provide for any energy deficiency and will purchase any excess energy supplied to the market thereby affecting the amount of energy the City procures.

\(^{(2)}\) The difference between the total kWh generated and purchased and the total kWh sold is due to transmission and/or distribution system losses.

Many of the Riverside Electric System’s industrial customers have loads under 500 kW. The Riverside Electric System’s commercial and industrial customer base, comprised of its five largest customers, provided approximately 11.67% of its revenues for the fiscal year ended June 30, 2014. The Riverside Electric System’s two largest customers provided approximately 3.70% and 2.82% of its revenues, respectively, for the fiscal year ended June 30, 2014.

### Electric Rates and Charges

Riverside is obligated by its City Charter and by the resolutions under which it has electric revenue bonds outstanding to establish rates and collect charges in an amount sufficient to meet its operation and maintenance expenses and debt service requirements, with specified requirements as to priority and coverage. Electric rates are established by the Riverside Board and subject to approval by the Riverside City Council. Electric rates are not subject to the general regulatory jurisdiction of the California Public Utilities Commission (“CPUC”) or by any other state agency. The CPUC contains certain provisions affecting all municipal utilities such as Riverside, including provisions for a public benefits charge. At this time, neither the CPUC nor any regulatory authority of the state nor FERC approves the City’s retail electric rates, although FERC does approve the City’s TRR included in the Transmission Access Charge collected from users of the CAISO transmission grid.

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

In January 1998, Riverside began collecting a surcharge for public benefit programs on customer utility bills. This surcharge was mandated by State legislation (i.e., AB 1890 and subsequent legislation) and is restricted to various socially-beneficial programs and services.

At present, the Riverside Electric System has 18 rate schedules in effect. Riverside provides no free electric service.
On December 19, 2006, the City Council approved a three-year Electric Reliability Rate Plan primarily to fund debt service for internal generation, a second point of interconnection to the State’s transmission grid and replace expiring low-cost power supply contracts at current market rates. This plan implemented a new Tier 3 and Tier 4 to the residential rate structure in order to encourage conservation. Riverside’s summer consumption typically doubles over the winter consumption due to Riverside’s semi-arid climate. As a result of the desert-type summers and implementation of additional tiers, residential customers experienced a wide-range of percentage increases. Consequently, on August 14, 2007, the City Council repealed the increases to Tiers 3 and 4 of the previously approved residential rate increase. The business rates were not repealed.

On December 4, 2007, the City Council unanimously approved a new three-year Electric Utility Rate Plan, with rate increases effective January 1, 2008, 2009 and 2010. Under this plan, a new Reliability Charge was implemented for all customer classes based upon either the maximum rated capacity for electric service at each individually metered site or a combination of such panel capacity and actual usage, all according to the customer’s applicable rate tariff. This charge is being used to fund two primary system reliability upgrades (98 MW of additional peaking generation and a second point of interconnection to the state’s high voltage transmission grid) which benefit all utility customers. In addition to the Reliability Charge, residential customers now have a third energy tier and a seasonal adjustment for energy usage. This seasonal adjustment will effectively reduce the summer bills and will result in slightly higher increases in the winter months.

On October 2, 2012, the City Council approved an Electric Rate Freeze through January 31, 2014 to allow Riverside to continue to provide rate certainty and predictability for business and residential customers. The Electric Rate Freeze was supported by Riverside Electric System’s strong operating results.

The Riverside Electric System’s base rates have been changed eight times over the period beginning January 1, 1998. The following table sets forth the percentage increase in rates for the indicated customer classes. Such percentage changes do not reflect changes in the power cost adjustment account, which is currently set at zero.

<table>
<thead>
<tr>
<th>Effective Date</th>
<th>Overall System</th>
<th>Residential</th>
<th>Commercial</th>
<th>Industrial</th>
</tr>
</thead>
<tbody>
<tr>
<td>January 1, 1998(1)</td>
<td>2.85%</td>
<td>2.85%</td>
<td>2.85%</td>
<td>2.85%</td>
</tr>
<tr>
<td>November 1, 2002(2)</td>
<td>3.40</td>
<td>4.00</td>
<td>3.00</td>
<td>3.00</td>
</tr>
<tr>
<td>November 1, 2003(2)</td>
<td>3.10</td>
<td>3.25</td>
<td>3.00</td>
<td>3.00</td>
</tr>
<tr>
<td>November 1, 2004(2)</td>
<td>2.20</td>
<td>2.50</td>
<td>2.00</td>
<td>2.00</td>
</tr>
<tr>
<td>January 1, 2007(3)</td>
<td>3.50</td>
<td>2.10</td>
<td>5.20</td>
<td>4.70</td>
</tr>
<tr>
<td>January 1, 2008(3)</td>
<td>10.00</td>
<td>13.50</td>
<td>10.50</td>
<td>8.90</td>
</tr>
<tr>
<td>January 1, 2009(3)</td>
<td>3.60</td>
<td>3.70</td>
<td>5.20</td>
<td>2.80</td>
</tr>
<tr>
<td>January 1, 2010(3)</td>
<td>5.80</td>
<td>8.60</td>
<td>4.80</td>
<td>5.40</td>
</tr>
</tbody>
</table>

(1) Public benefit surcharge pursuant to AB 1890.
(2) Three–year rate increase approved by City Council on June 4, 2002.
(3) Combined effect of Electric Reliability Rate Plan and Electric Utility Rate Plan approved by City Council on December 1, 2006 and December 4, 2007, respectively.

Unrestricted Cash Reserves

Effective July 1, 2003, the City Council approved a Regulatory Risk Reserve Account in the amount of $4.0 million, an Energy Risk Management Reserve Account in the amount of $11.0 million,
and an Operating Reserve Account of $14.0 million, all of which are considered internally restricted assets. Additionally, an internally restricted decommissioning reserve account has been established for future unknown costs related to SONGS decommissioning. This reserve is separate from the accumulated resources set aside in a trust for decommissioning obligations of SONGS which is considered to be fully funded based on the cost estimate prepared by ABZ Incorporated in July 2013. Internally restricted assets are restricted only by internal policy and not otherwise legally restricted. The combined balances of the reserve accounts were $177.8 million at June 30, 2014 and are included in unrestricted cash and investments on the Riverside Electric System Statements of Net Position. These funds are available for current operations, or other strategic purposes upon approval of the Riverside Board and the City Council.

**Indebtedness; Joint Powers Agency Obligations**

As of December 31, 2014, Riverside had outstanding approximately $582.7 million aggregate principal amount of bonds which are payable from and secured by a pledge of and lien on net operating revenues of the Electric System.

In addition, Riverside participates in contracts with Intermountain Power Agency (“IPA”) and the Authority. Obligations of Riverside under the agreements with IPA and the Authority constitute operating and maintenance expenses of Riverside payable prior to any of the payments required to be made on the Riverside Electric System bonds and any parity debt. Agreements between Riverside and IPA and Riverside and the Authority are on a “take-or-pay” basis, which requires payments to be made whether or not applicable projects are completed or operable, or whether output from such projects is suspended, interrupted or terminated. All of these agreements contain “step-up” provisions obligating Riverside to pay a share of the obligations of a defaulting participant. Any “step-up” obligation relating to Riverside’s participation in transmission projects that it would be responsible for would be included in Riverside’s TRR (that would require filing a new TRR at the FERC) and would be recovered from all CAISO grid users. Riverside’s participation and share of principal 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:

<table>
<thead>
<tr>
<th>OUTSTANDING DEBT OF JOINT POWERS AGENCIES</th>
<th>(Dollars in Thousands)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>As of December 31, 2014</strong></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Principal Amount of Outstanding Debt</th>
<th>Riverside Share of Principal Amount of Outstanding Debt</th>
</tr>
</thead>
<tbody>
<tr>
<td>Intermountain Power Agency</td>
<td></td>
</tr>
<tr>
<td>Intermountain Power Project(3)</td>
<td>$1,530,540</td>
</tr>
<tr>
<td>Participation(1)</td>
<td>7.617%</td>
</tr>
<tr>
<td></td>
<td>$ 116,581</td>
</tr>
<tr>
<td>Southern California Public Power Authority</td>
<td></td>
</tr>
<tr>
<td>Palo Verde Nuclear Generating Station</td>
<td>36,130</td>
</tr>
<tr>
<td>Participation</td>
<td>5,400</td>
</tr>
<tr>
<td></td>
<td>1,951</td>
</tr>
<tr>
<td>Southern Transmission System</td>
<td>657,630</td>
</tr>
<tr>
<td>Participation</td>
<td>10,200</td>
</tr>
<tr>
<td></td>
<td>67,078</td>
</tr>
<tr>
<td>Hoover Dam Uprating</td>
<td>6,095</td>
</tr>
<tr>
<td>Participation</td>
<td>31,900</td>
</tr>
<tr>
<td></td>
<td>1,944</td>
</tr>
<tr>
<td>Mead-Phoenix Transmission</td>
<td>33,175</td>
</tr>
<tr>
<td>Participation</td>
<td>4,000</td>
</tr>
<tr>
<td></td>
<td>1,327</td>
</tr>
<tr>
<td>Mead-Adelanto Transmission</td>
<td>108,785</td>
</tr>
<tr>
<td>Participation</td>
<td>13,500</td>
</tr>
<tr>
<td></td>
<td>14,686</td>
</tr>
<tr>
<td>Total</td>
<td>$2,372,355</td>
</tr>
<tr>
<td></td>
<td>$203,567</td>
</tr>
</tbody>
</table>

(1) Participation obligation is subject to increase upon default of another project participant.

(2) Excludes interest on the debt.

(3) Includes commercial paper and subordinate notes.
For the fiscal year ended June 30, 2014, Riverside’s obligations for debt service on its joint powers agency obligations aggregated approximately $33.9 million. Riverside’s obligation for debt service on joint powers agency obligations in the future is expected to be a high of approximately $35.1 million in the fiscal year ending June 30, 2016, but is expected to decline to approximately $3.6 million in fiscal year 2028. This projection assumes no future debt issuances, and that the interest rate on unhedged (not otherwise fixed through interest rate swap agreements) variable rate joint powers agency debt obligations will be 4.5%. As of June 30, 2014, a portion of the joint powers agency obligation debt service was unhedged variable rate debt. Unreimbursed draws under liquidity arrangements supporting joint powers agency variable rate debt obligations bear interest at a maximum rate substantially in excess of the assumed rates stated above. 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 addition, swap agreements entered into by the joint powers agencies are subject to early termination under certain circumstances, in which event substantial payments could be required to be made to the applicable swap provider.

Litigation

On May 11, 2004, the CAISO filed Amendment No. 60 to its Tariff to modify the CAISO’s process for dispatching generation and allocating associated costs. Numerous parties, including the City as a member of the “Southern Cities” group, submitted testimony to the FERC on the allocation of these costs, and a hearing was held in 2005. On October 31, 2005 the Presiding Administrative Law Judge issued an Initial Decision, and on December 27, 2006, the FERC issued an order generally affirming the determinations in the Initial Decision. The FERC order adopted the City’s position with respect to “South-of-Lugo” costs, which would have resulted in a large part of these generation dispatch costs being allocated to Edison. On November 20, 2007, the FERC issued its Order on Rehearing, reversing its position on South-of-Lugo costs in a manner that would require the City to share these costs. The City and a number of other parties filed requests for rehearing of the Order on Rehearing. On September 16, 2011, FERC issued an Order Denying Rehearing of the Order on Rehearing. The City (along with other municipal electric systems) filed a timely petition for review with the United States Court of Appeals for the District of Columbia Circuit, Case No. 11-1442. Final briefs by all parties were submitted to the Court of Appeals on September 26, 2012. In November 2013, the Court of Appeals rejected the petition for review of FERC’s decision in the Amendment 60 case.

In May 2014, the CAISO completed its recalculation of the Amendment 60 costs with the exception of the interest which is still an outstanding issue for the parties. The City has paid its portion of the settlement amount to the CAISO which was $2.285 million and the parties have filed protests with FERC regarding the assessment of interest. FERC has not yet ruled on the pending protests and CAISO has deferred invoicing of interest until further notice. The City cannot predict the outcome of FERC’s ruling. However, the City believes the amount to be immaterial.

On July 18, 2013, the City filed a lawsuit in the San Diego County Superior Court against Mitsubishi Heavy Industries (“MHI”) for breach of contract, negligence and misrepresentation related to defective steam generators replaced in SONGS Units 2 and 3. On July 24, 2013, MHI moved the lawsuit to the United States District Court for the Southern District of California, and on August 8, 2013, MHI moved to stay the proceeding pending resolution of the dispute resolution process involving MHI and Edison arising from the contract for the purchase and sale of the steam generators. In October 2013, after a prescribed 90-day waiting period from the service of an earlier notice of dispute, Edison initiated an arbitration proceeding against MHI seeking damages stemming from the failure of the replacement steam generators. In late December 2013, MHI answered and filed a counter-claim against Edison. On March 14, 2014, the Federal District court granted MHI’s motion to stay the City’s proceeding, but ordered that the City participate in the Edison/MHI arbitration. Edison, SDGE, the City and MHI have all stipulated that the City and SDGE shall participate in the Edison/MHI arbitration before the ICC. A six-
week arbitration is scheduled to begin on March 21, 2016. The amount of damages claimed is in excess of $4.4 billion.

The steam generators were designed and manufactured by MHI and were warranted for an initial period of 20 years. MHI was contractually obligated to repair or replace defective items and to pay specified damages for certain repairs. MHI and Edison are in a disagreement regarding the liability limits of the purchase agreement. Edison has submitted claims for repair costs which MHI has denied a portion of the costs pending further documentation. As a result, Edison has filed claims against their two insurance policies issued by Nuclear Electric Insurance Limited (“NEIL”) of which the City is a named insured. Cost to the City associated with SONGS Units 2 and 3 may be reduced by third-party recoveries, if any.

As a result of the decision by Edison to permanently retire Units 2 and 3 of SONGS prior to the expiration of the Nuclear Regulatory Commission licenses, the City expects to incur certain costs resulting from the early termination of long-term uranium fuel supply contracts. On November 12, 2013, Uranium One Inc. served a Demand for Arbitration on Edison, SDG&E and the City, seeking an award of damages in the approximate amount of $12.5 million. Uranium One, Inc. asserts damages from a purchase agreement to deliver certain amounts of uranium concentrates in 2011, 2012 and 2013. On April 25, 2014, Energy Resources of Australia, Ltd. and Rossing Uranium Ltd. served a Demand for Arbitration on Edison, asserting similar claims as Uranium One Inc. and seeking an award of damages in the approximate amount of $19.5 million. No arbitration dates have been set and the City cannot estimate the outcomes of these pending claims at this time.

In February 2005, claimants filed a lawsuit in the Utah state court, entitled Gunn Hill Dairy Properties, LLC, et al. v. Los Angeles Department of Power, et al., Case No. 050700157, naming the Authority (the entity financing the Southern Transmission System’s (“STS”) facilities), the Los Angeles Department of Water and Power (“LADWP”) (the operator of the STS facilities), the IPA (the owners of the STS facilities), and others as defendants. The plaintiff dairies seek compensatory damages in excess of $515 million plus punitive damages. In November 2013, a mistrial was declared in the case relating to six of the plaintiff dairies. Subsequent to the mistrial, these six plaintiff dairies filed a motion for sanctions and for a change of venue, which was denied. In October 2014, the court entered a formal order to that effect. In October 2014, the original six plaintiffs filed a petition for leave to appeal the October order. In November 2014, the Utah Court of Appeals granted the petition for leave to appeal the denial of the motion to change the venue, but denied permission to appeal the trial court’s denial of the original six plaintiffs’ motion for sanctions. Plaintiffs then filed a motion in the trial court to stay the proceedings in the trial court pending the outcome of the appeal. By order dated December 2, 2014, the trial court stayed all proceedings before it, pending resolution of the appeal. Because a mistrial was declared during the first trial, the claims of the six original plaintiffs will need to be re-tried. The trial court set summer 2015 dates for the re-trial. The separate trial or trials for the other two plaintiff dairy groups have not yet commenced.

LADWP has stated that it believes that on the law and facts, defendants should prevail. However, given, among other factors, that the court declined to dismiss the original six plaintiffs’ negligence claim and will allow it to be presented to a jury, and the unpredictable nature of a jury trial, IPA and LADWP have indicated that they cannot predict the outcome of the plaintiffs’ claims. In the event that damages are awarded to the plaintiff dairies against the IPA, any part of the award not otherwise covered by insurance may be apportioned among utilities that purchase IPP capacity in accordance with their entitlement shares.

Pending lawsuits and other claims against the City with respect to the Riverside Electric System are incidental to the ordinary course of operations of the Electric System and are largely covered by the City’s self-insurance program. In the opinion of the Electric System’s management and the City
Attorney, such lawsuits and claims will not have a materially adverse effect upon the financial position of the Riverside Electric System.

State and Federal Legislation

Set forth below is a brief discussion of certain State and federal legislation affecting the electric industry and the Electric System. See also “DEVELOPMENTS IN THE CALIFORNIA ENERGY MARKETS” and “OTHER FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY” in the front part of this Official Statement.

**Senate Bill (SB) X1-2 – California Renewable Energy Resource Act**

Enacted in 2011, SBX1-2 requires utilities, including publicly-owned utilities (“POUs”), to achieve a 33% Renewable Portfolio Standard (“RPS”) by 2020, with interim targets of an average of 20% for the period 2011 to 2013, 25% by 2016, and 33% by 2020 and subsequent years. Additionally, SBX1-2 requires POUs to adopt and implement a Renewable Energy Resource Procurement Plan (“Plan”). The Plan must require the utility to procure a minimum quantity of electricity products from eligible renewable energy resources.

Oversight of compliance with SBX1-2 by POUs is provided in part by their respective local governing bodies and in part by the California Energy Commission (“CEC”). Oversight of compliance by investor-owned utilities (“IOUs”) is provided by the California Public Utilities Commission (“CPUC”).

The City has completed a conceptual RPS Procurement Plan and has received approval from City Council to implement the Plan. The Plan outlines a diverse portfolio of specific geothermal, wind, utility-scale solar photovoltaic, distributed solar photovoltaic, and small hydro resources. To date, the City has completed the procurement of eligible renewable resources to meet the target for the period of 2011-13 and has substantially completed the procurement of eligible renewable resources to meet the stated targets through 2020.

**Assembly Bill (AB) 32 – Global Warming Solutions Act of 2006**

AB 32 requires that utilities in California reduce their greenhouse gas (“GHG”) emissions to 1990 levels by the year 2020.

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

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

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

**Senate Bill (SB) 1 – California Solar Initiative**

SB 1, enacted in 2006, requires municipal utilities to establish a program supporting the stated
goal of the legislation to install 3,000 MW of photovoltaic (“PV”) resources in California. Municipal
utilities are also required to establish eligibility criteria in collaboration with the CEC for funding solar
energy systems receiving ratepayer funded incentives and meet reporting requirements regarding the
installed capacity, number of installed systems, number of applicants, and awarded incentives.

The City has demonstrated leadership through its commitment to solar generations, with the
construction of its first PV project in 2002, having a capacity of 150 kilowatts. To date, the City has
increased its efforts and now has more than 10 MW of PV within the City.

**Dodd-Frank Wall Street Reform And Consumer Protection Act (Dodd-Frank Act)**

In July 2010, the Dodd-Frank Act (“Act”) was enacted to provide regulatory oversight and
transparency of financial institutions primarily as a result of the economic meltdown. A portion of the Act
provides a framework for the regulation of swap markets which is expected to have the largest impact on
the functions of the utility industry. Swaps were previously exempt from regulatory oversight and
considered a normal activity in the utility industry to reduce business risk and price volatility. The Act
mandates that the Commodity Futures Trading Commission govern the rulemaking process of swaps.

The requirements under the Act include, but are not limited to, mandatory clearing and trade
execution requirements, reporting and recordkeeping obligations, registration of large financial
participants in the swap markets, and most likely position limits on energy and other contracts.

Overall, the impact of the Act to the City is on reporting and recordkeeping of transactions and it
is expected to be manageable due to the fact that the City is a Special Entity as well as an end-user.
Therefore, most of the reporting obligations fall under the City’s transaction counterparties.

On September 17, 2014, the CFTC issued a final rule that provides permanent relief from swap
dealer regulation for utility operations-related swaps by utility special entities. This rule will help ensure
that public power utilities have access to the counterparties needed to hedge fuel and electric power price
risks.

**Summary of Operations**

The following table shows the Net Operating Revenues of the Electric System available for debt
service on its Electric System revenue bonds and depreciation as calculated in accordance with the flow
of funds in Riverside’s bond resolution, and has been prepared by Riverside based upon audited financial
statements for the Riverside Electric System for fiscal years 2010 through 2014.
Riverside Electric System  
Summary of Operations and Debt Service Coverage (1)  
($000's)  

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Operating Revenues:</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Residential</td>
<td>$111,880</td>
<td>$118,173</td>
<td>$110,471</td>
<td>$107,792</td>
<td>$107,301</td>
</tr>
<tr>
<td>Commercial, Industrial and Other</td>
<td>183,923</td>
<td>183,024</td>
<td>179,116</td>
<td>171,635</td>
<td>168,188</td>
</tr>
<tr>
<td>Wholesale Sales</td>
<td>115</td>
<td>638</td>
<td>50</td>
<td>124</td>
<td>1,466</td>
</tr>
<tr>
<td>Transmission Revenues (1)</td>
<td>32,630</td>
<td>32,688</td>
<td>30,735</td>
<td>22,091</td>
<td>21,100</td>
</tr>
<tr>
<td>Other</td>
<td>6,912</td>
<td>4,486</td>
<td>4,018</td>
<td>4,015</td>
<td>3,806</td>
</tr>
<tr>
<td>Total Operating Revenues Before Reserve/Recovery</td>
<td>335,460</td>
<td>339,009</td>
<td>324,390</td>
<td>305,657</td>
<td>301,861</td>
</tr>
<tr>
<td>Reserve for Uncollectible, Net of Reserve/Recovery</td>
<td>(589)</td>
<td>(959)</td>
<td>(971)</td>
<td>(1,021)</td>
<td>(1,283)</td>
</tr>
<tr>
<td>Total Operating Revenues, Net of Reserve/Recovery</td>
<td>$334,871</td>
<td>$338,050</td>
<td>$323,419</td>
<td>$304,636</td>
<td>$300,578</td>
</tr>
<tr>
<td><strong>Interest Income</strong></td>
<td>6,041</td>
<td>3,060</td>
<td>6,196</td>
<td>10,368</td>
<td>16,009</td>
</tr>
<tr>
<td>Capital Contributions</td>
<td>2,890</td>
<td>3,557</td>
<td>7,425</td>
<td>2,058</td>
<td>1,610</td>
</tr>
<tr>
<td>Non-Operating Revenues</td>
<td>3,738</td>
<td>3,520</td>
<td>3,058</td>
<td>2,117</td>
<td>2,362</td>
</tr>
<tr>
<td>Total Revenues (2)</td>
<td>$347,540</td>
<td>$348,187</td>
<td>$340,098</td>
<td>$319,179</td>
<td>$320,559</td>
</tr>
</tbody>
</table>

| Operating Expenses:       |        |        |        |        |        |
| Nuclear Production        | 5,254 | 15,988 | 17,054 | 16,582 | 17,496 |
| Purchased Power           | 133,568 | 115,473 | 111,208 | 110,930 | 106,878 |
| Transmission Expenses     | 51,939 | 45,957 | 45,447 | 40,434 | 33,030 |
| Distribution Expenses     | 14,160 | 13,730 | 13,479 | 13,175 | 12,930 |
| Customer Account Expenses | 6,103 | 6,978 | 6,439 | 6,731 | 6,940  |
| Customer Service Expenses | 3,168 | 2,089 | 1,834 | 1,510 | 1,460  |
| Administration & General Expenses | 13,540 | 15,179 | 14,972 | 12,422 | 10,447 |
| Clearing & Miscellaneous Expenses | 13,403 | 11,603 | 11,443 | 11,094 | 9,859  |
| Total Expenses (2)(3)     | $241,135 | $226,997 | $221,876 | $212,878 | $199,040 |

| Net Operating Revenues Available for Debt Service and Depreciation | $106,405 | $121,190 | $118,222 | $106,301 | $121,519 |
| Debt Service Requirements on Electric System Bonds | $49,207 | $44,426 | $52,803 | $48,116 | $44,146 |
| Debt Service Coverage Ratio | 2.16x | 2.73x | 2.24x | 2.21x | 2.75x |

(1) Includes additional revenues as a result of becoming a PTO with the CAISO effective January 1, 2003.
(2) Excludes restricted revenues generated from the Public Benefits Charge (PBC) and expenses incurred from the related program.
(3) Does not include contributions to City’s General Fund of $33,656, $33,070, $33,533, $37,186, and $38,704 for fiscal years 2009-10 through 2013-14, respectively.

The following Statements of Net Position has been prepared by Riverside based upon audited financial statements of the Riverside Electric System for fiscal years 2010 through 2014.
Riverside Electric System – Electric Statements of Net Position ($000)\(^{(1)}\)

<table>
<thead>
<tr>
<th>Assets and Deferred Outflows of Resources</th>
<th>2014</th>
<th>2013</th>
<th>2012</th>
<th>2011</th>
<th>2010</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Utility plant</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Production(^{(3)})</td>
<td>$267,152</td>
<td>$266,791</td>
<td>$349,264</td>
<td>$426,575</td>
<td>$274,392</td>
</tr>
<tr>
<td>Transmission</td>
<td>42,963</td>
<td>35,176</td>
<td>32,054</td>
<td>29,152</td>
<td>28,484</td>
</tr>
<tr>
<td>Distribution</td>
<td>541,381</td>
<td>514,336</td>
<td>494,918</td>
<td>463,437</td>
<td>440,297</td>
</tr>
<tr>
<td>General</td>
<td>60,600</td>
<td>58,827</td>
<td>53,793</td>
<td>52,982</td>
<td>55,857</td>
</tr>
<tr>
<td>Intangible</td>
<td>325</td>
<td>292</td>
<td>292</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td><strong>Less accumulated depreciation(^{(3)})</strong></td>
<td>(291,478)</td>
<td>(268,211)</td>
<td>(311,039)</td>
<td>(352,343)</td>
<td>(331,216)</td>
</tr>
<tr>
<td><strong>Total utility plant</strong></td>
<td>$620,943</td>
<td>$607,211</td>
<td>$619,282</td>
<td>$619,803</td>
<td>$467,814</td>
</tr>
<tr>
<td><strong>Restricted assets(^{(4)})</strong></td>
<td>205,166</td>
<td>237,585</td>
<td>263,117</td>
<td>297,089</td>
<td>208,779</td>
</tr>
<tr>
<td><strong>Current assets:</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cash and investments(^{(5)})</td>
<td>210,929</td>
<td>197,823</td>
<td>187,541</td>
<td>168,905</td>
<td>170,292</td>
</tr>
<tr>
<td>Accounts receivable, net(^{(3)})</td>
<td>36,680</td>
<td>40,955</td>
<td>35,899</td>
<td>35,524</td>
<td>31,509</td>
</tr>
<tr>
<td>Advances to other funds(^{(3)})</td>
<td>914</td>
<td>1,765</td>
<td>2,277</td>
<td>4,195</td>
<td>0</td>
</tr>
<tr>
<td>Accrued interest receivable</td>
<td>1,127</td>
<td>1,089</td>
<td>825</td>
<td>1,381</td>
<td>913</td>
</tr>
<tr>
<td>Inventory</td>
<td>1,202</td>
<td>507</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Prepaid expenses</td>
<td>22,827</td>
<td>21,869</td>
<td>20,018</td>
<td>12,660</td>
<td>10,748</td>
</tr>
<tr>
<td>Unamortized purchased power</td>
<td>372</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Nuclear materials inventory(^{(3)})</td>
<td>0</td>
<td>1,992</td>
<td>1,905</td>
<td>1,825</td>
<td></td>
</tr>
<tr>
<td><strong>Total restricted and current assets</strong></td>
<td>479,217</td>
<td>501,593</td>
<td>511,669</td>
<td>521,659</td>
<td>424,066</td>
</tr>
<tr>
<td><strong>Other non-current assets:</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Advances to other funds(^{(3)})</td>
<td>5,800</td>
<td>5,742</td>
<td>5,558</td>
<td>5,558</td>
<td>650</td>
</tr>
<tr>
<td>Net pension asset(^{(1)})</td>
<td>11,450</td>
<td>11,954</td>
<td>12,380</td>
<td>12,736</td>
<td>13,027</td>
</tr>
<tr>
<td>Unamortized purchased power</td>
<td>3,143</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Regulatory assets(^{(2)})</td>
<td>17,451</td>
<td>18,281</td>
<td>6,502</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Deferred bond issuance(^{(1)(2)})</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>7,128</td>
<td>6,847</td>
</tr>
<tr>
<td>Deferred debits(^{(4)(7)})</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>10,016</td>
<td>18,279</td>
</tr>
<tr>
<td><strong>Total other non-current assets</strong></td>
<td>37,844</td>
<td>35,977</td>
<td>24,440</td>
<td>35,438</td>
<td>38,803</td>
</tr>
</tbody>
</table>

| Deferred outflows of resources\(^{(1)}\) |            |            |            |            |            |
| Deferred changes in derivative values\(^{(7)}\) | 16,336     | 17,371     | 30,876     | 0          | 0          |
| Deferred loss on refunding\(^{(6)}\)      | 12,952     | 11,917     | 12,881     | 0          | 0          |
| **Total deferred outflows of resources**  | 29,288     | 29,288     | 43,757     | 0          | 0          |
| **Total assets and deferred outflows of resources** | $1,237,765 | $1,245,905 | $1,283,301 | $1,239,031 | $1,069,646 |

(continued on following page)
## Net Position and Liabilities

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Net position</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Net investment in capital assets</td>
<td>$196,771</td>
<td>$201,765</td>
<td>$236,789</td>
<td>$224,953</td>
<td>$222,016</td>
</tr>
<tr>
<td>Restricted for debt service</td>
<td>15,808</td>
<td>16,354</td>
<td>19,808</td>
<td>22,237</td>
<td>21,215</td>
</tr>
<tr>
<td>Restricted for regulatory requirements</td>
<td>3,150</td>
<td>381</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Restricted for public benefit programs</td>
<td>9,732</td>
<td>9,076</td>
<td>4,020</td>
<td>3,771</td>
<td>7,389</td>
</tr>
<tr>
<td>Unrestricted</td>
<td>258,514</td>
<td>241,696</td>
<td>219,198</td>
<td>199,159</td>
<td>189,431</td>
</tr>
<tr>
<td><strong>Total net position</strong></td>
<td>$483,975</td>
<td>$469,272</td>
<td>$479,815</td>
<td>$450,120</td>
<td>$440,051</td>
</tr>
<tr>
<td><strong>Long-term obligations, less current portion</strong></td>
<td>$593,108</td>
<td>$563,203</td>
<td>$585,263</td>
<td>$594,714</td>
<td>$479,174</td>
</tr>
<tr>
<td><strong>Total net position and long-term obligations</strong></td>
<td>$1,077,083</td>
<td>$1,032,475</td>
<td>$1,065,078</td>
<td>$1,044,834</td>
<td>$919,225</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Non-current liabilities:</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Compensated absences</td>
<td>830</td>
<td>762</td>
<td>803</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Capital leases payable</td>
<td>1,566</td>
<td>1,913</td>
<td>901</td>
<td>1,303</td>
<td>1,699</td>
</tr>
<tr>
<td>Advance from other funds-pension obligation</td>
<td>11,284</td>
<td>11,781</td>
<td>12,003</td>
<td>12,381</td>
<td>12,705</td>
</tr>
<tr>
<td>Nuclear decommissioning liability</td>
<td>75,299</td>
<td>76,167</td>
<td>71,709</td>
<td>67,969</td>
<td>63,552</td>
</tr>
<tr>
<td>Postemployment benefits payable</td>
<td>5,749</td>
<td>4,928</td>
<td>3,809</td>
<td>2,775</td>
<td>2,004</td>
</tr>
<tr>
<td>Loan payable-Corona</td>
<td>0</td>
<td>7,413</td>
<td>42,660</td>
<td>44,141</td>
<td>0</td>
</tr>
<tr>
<td>Derivative instruments</td>
<td>22,108</td>
<td>23,729</td>
<td>38,123</td>
<td>17,216</td>
<td>22,073</td>
</tr>
<tr>
<td><strong>Total non-current liabilities</strong></td>
<td>$116,836</td>
<td>$126,693</td>
<td>$170,008</td>
<td>$145,785</td>
<td>$102,033</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Current liabilities payable from restricted assets:</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Accounts payable and other accruals</td>
<td>1,869</td>
<td>718</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Accrued interest payable</td>
<td>5,770</td>
<td>5,970</td>
<td>6,100</td>
<td>6,382</td>
<td>4,085</td>
</tr>
<tr>
<td>Public benefit programs payable</td>
<td>154</td>
<td>643</td>
<td>1,035</td>
<td>808</td>
<td>396</td>
</tr>
<tr>
<td>Current portion of long-term obligations</td>
<td>14,920</td>
<td>20,685</td>
<td>18,050</td>
<td>20,940</td>
<td>22,705</td>
</tr>
<tr>
<td><strong>Total current liabilities payable from restricted assets</strong></td>
<td>$22,713</td>
<td>$28,016</td>
<td>$25,185</td>
<td>$28,130</td>
<td>$27,186</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Current liabilities:</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Accounts payable and other accruals</td>
<td>17,289</td>
<td>20,102</td>
<td>18,401</td>
<td>15,821</td>
<td>18,314</td>
</tr>
<tr>
<td>Loan payable-Corona</td>
<td>0</td>
<td>35,248</td>
<td>1,481</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Customer deposits</td>
<td>3,844</td>
<td>3,371</td>
<td>3,148</td>
<td>4,461</td>
<td>2,888</td>
</tr>
<tr>
<td><strong>Total current liabilities</strong></td>
<td>$21,133</td>
<td>$58,721</td>
<td>$23,030</td>
<td>$20,282</td>
<td>$21,202</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Total net position and liabilities</strong></td>
<td>$1,237,765</td>
<td>$1,245,905</td>
<td>$1,283,301</td>
<td>$1,239,031</td>
<td>$1,069,646</td>
</tr>
</tbody>
</table>

---

(1) In fiscal year 2013, Riverside implemented new financial accounting standards which renamed and added classifications to the financial statements. The financial statements have been revised to reflect the new reporting requirements including the restatement of fiscal year ended June 30, 2012 for comparative purposes.

(2) Riverside elected to record debt issuance costs and replacement power costs as regulatory assets which allows for deferring these expenses to be reflected in future rates.

(3) SONGS Unit 2 and 3 were taken offline in January 2012, and on June 7, 2013, Edison announced its decision to retire Units 2 and 3 permanently. Due to the prior uncertainty of the SONGS Unit 3 restart date, in June 2012, the capital asset was reclassified from a depreciable to a non-depreciable utility plant asset until it is a restored service. However, since Edison’s announcement to retire SONGS Units 2 and 3, SONGS net book value of $41.2 million (including nuclear fuel and nuclear materials inventory) was written off and removed from the utility plant assets at June 30, 2013.

(4) Includes current and non-current restricted assets for historical comparison purposes.

(5) See discussion under “Unrestricted Cash Reserves.”

(6) As a result of new financial accounting standards, deferred loss on refunding which was previously netted with long-term obligations has been reclassified as deferred outflow of resources.

(7) As a result of new financial accounting standards, previously reported deferred debits have been reclassified as deferred changes in derivative values under the classification of deferred outflow of resources.

(8) Represents the City’s obligations in connection with the Corona COPs, of which electric revenue bonds were issued in July 2013 to prepay the outstanding obligation to the City of Corona.
Labor Relations

As of June 30, 2014, 463 City employees were assigned specifically to the Riverside Electric System. Certain functions supporting the Riverside Electric System operations, including meter reading, customer billing and collections, are performed by the staff of the Riverside Public Utilities Department. Substantially all of the non-administrative City personnel assigned to the Riverside Electric System are represented by the International Brotherhood of Electrical Workers (“IBEW”). The City and IBEW are parties to a Memorandum of Understanding that expires on September 30, 2016. Portions of the administrative staff are represented by the Service Employees International Union (“SEIU”). The City and the SEIU are parties to a Memorandum of Understanding that expires on June 30, 2016. The Riverside Electric System has faced no strikes or other work stoppages within the last ten years, and the City does not anticipate any in the near future.

Retirement Programs

Employee Retirement System

Retirement benefits to City employees, including those assigned to the Riverside Electric System, are provided through the City’s participation in the Public Employees Retirement System (“CalPERS”) of California, an agency, multiple-employer, public employee retirement system that acts as a common investment and administrative agency for participating public entities within the State of California. CalPERS issues a separate, publicly available financial report that includes financial statements and required supplemental information of participating public entities within the State of California. Copies of the CalPERS annual financial report may be obtained from the CalPERS Executive Office, Lincoln Plaza Complex, 400 Q Street, Sacramento, California 95811 or at www.calpers.ca.gov.

All permanent full-time and selected part-time employees of the City are eligible for participation in CalPERS. Benefits vest after five years of service and are determined by a formula that considers the employee’s age, years of service, and salary. Employees hired prior to January 1, 2013, may retire at age 55, and receive 2.7% of their highest salary for each year of service completed. All of the bargaining units included in the Miscellaneous CalPERS plan, including Management, SEIU, and IBEW employees of the Electric System, agreed to change the calculation of the CalPERS retirement benefit for new employees from utilizing the highest year of salary to the average of the highest three years of salary, which addressed concerns associated with salary increases in the year immediately prior to retirement. This change was effective for employees hired on or after December 9, 2011. The California Public Employees’ Pension Reform Act of 2012 (“PEPRA”) enacted statewide pension reforms effective January 1, 2013. Employees hired after January 1, 2013, may retire at age 62 and receive 2.0% of their highest salary for each year of service completed. The formula is adjusted to encourage employees to retire at later ages, with a 2.5% factor at age 67 being the maximum. The average highest three years of salary continue to be used to calculate the retirement benefit under the new plan. CalPERS also provides death and disability benefits. These benefit provisions and all other requirements are established by State statute and City ordinance.

For each of the fiscal years ended June 30, 2010 through June 30, 2014, the City has contributed to CalPERS at the actuarially determined rate provided by CalPERS actuaries. Participants in the Miscellaneous Plan hired prior to January 1, 2013, are required to contribute 8% of their annual covered salary, while employees hired after January 1, 2013, are required to contribute 7% of their annual covered salary. The Riverside Electric System is required to contribute the remaining amounts necessary to fund the benefits for its employees using the actuarial basis recommended by the CalPERS actuaries and actuarial consultants and adopted by the CalPERS Board of Administration. The Riverside Electric System pays both the employee and employer contributions for employees hired prior to October 19, 2011, with the exception of general SEIU employees hired before this date, who contributed 2% of the
employee share in the year ended June 30, 2014, while the City contributed the remaining 6%. Beginning
July 1, 2014, general SEIU employees contribute 4% of the employee share with the City contributing the
remaining 4%, and beginning July 1, 2015 these employees will contribute 6% of the employee share
with the City contributing the remaining 2%. These increased employee contributions are being offset by
equivalent salary increases applicable only to the general SEIU employees hired prior to October 19,
2011. Employees hired on or after October 19, 2011 pay their own 8% or 7% contribution. PEPRA
established 50/50 cost sharing between the employer and employee for new employees hired on or after
January 1, 2013, which sharing applies to the normal cost component of the pension rate only (excluding
any unfunded liability component of the rate). This provision was immediately effective for Management
employees but was not effective for IBEW and SEIU employees until the expiration of the memoranda of
understanding then in place with these unions. The contribution requirements of plan members and the
City are established and may be amended by CalPERS.

PEPRA also established a cap on the amount of compensation that can be used to calculate the
retirement benefit for employees hired on or after January 1, 2013, which limits the benefit to 120% of the
Social Security wage index limit for 2013 of $136,440 for employers not participating in Social Security
such as the Electric System. This cap will be adjusted annually by the Consumer Price Index for all
Urban Consumers. PEPRA also prevents employers from offering defined benefit plans for
compensation in excess of the cap, but does allow for contributions to a defined contribution plan for
compensation in excess of the cap. PEPRA specifies that employees will not have a vested right to any
employer contributions to defined contribution plans related to this provision. The City of Riverside has
not made any enhancements to the compensation package for employees hired on or after January 1,
2013, with compensation exceeding the cap.

The Electric System’s total contribution to CalPERS as of June 30, 2014 and 2013 was
$8,542,000 and $8,633,000, respectively. In addition, the Electric System is obligated to pay its share of
the City’s pension obligation bonds, which the City issued in 2005 (the “Pension Obligation Bonds”).
The Electric System’s total proportionate share of the outstanding principal amount of the Pension
Obligation Bonds was $11,284,000 and $11,781,000 as of June 30, 2014 and 2013, respectively, which is
payable as an operating and maintenance expense of the Electric System. That share is recorded as an
inter-fund loan between the City General Fund and the Electric Utility Enterprise Fund and will amortize
based on the amortization schedule of the Pension Obligation Bonds. Citywide information concerning
elements of the unfunded actuarial accrued liabilities, contributions to CalPERS and recent trend
information may be found in the notes to the City’s Comprehensive Annual Financial Report for the year
ended June 30, 2014, which is available in late December on the City’s website at www.riversideca.gov.

More recent information as to the actuarial status of the City’s Miscellaneous Plan has been
provided in CalPERS’ Annual Valuation Report, dated October 2014, with respect to the City.

As shown in the table below, the report provides a recent history of the City’s contribution rates
for its Miscellaneous Plan, as determined by the annual actuarial valuation. The following table does not
account for prepayments or benefit changes made in the middle of the year.
City of Riverside
CalPERS Miscellaneous Plan
Contribution Rate History

<table>
<thead>
<tr>
<th>Fiscal Year</th>
<th>Employer Normal Cost</th>
<th>Unfunded Rate</th>
<th>Total Employer Contribution Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>2009-10</td>
<td>12.043%</td>
<td>2.176%</td>
<td>14.219%</td>
</tr>
<tr>
<td>2010-11</td>
<td>11.987</td>
<td>2.520</td>
<td>14.507</td>
</tr>
<tr>
<td>2011-12</td>
<td>11.823</td>
<td>6.615</td>
<td>18.438</td>
</tr>
<tr>
<td>2012-13</td>
<td>11.814</td>
<td>6.463</td>
<td>18.277</td>
</tr>
<tr>
<td>2013-14</td>
<td>11.851</td>
<td>6.463</td>
<td>18.314</td>
</tr>
<tr>
<td>2014-15</td>
<td>11.554</td>
<td>7.440</td>
<td>18.994</td>
</tr>
</tbody>
</table>

In addition, the report provides the recent history of the Actuarial Accrued Liability, the Market Value of Assets, funded ratio and the annual covered payroll as shown in the table below. The funded ratio is an indicator of the short-term solvency of the plan.

City of Riverside
CalPERS Miscellaneous Plan
City’s Funding History

<table>
<thead>
<tr>
<th>Valuation Date (June 30)</th>
<th>Actuarial Accrued Liability</th>
<th>Market Value of Assets (MVA)</th>
<th>Funded Ratio</th>
<th>Annual Covered Payroll</th>
</tr>
</thead>
<tbody>
<tr>
<td>2007</td>
<td>$770,088,775</td>
<td>$847,867,117</td>
<td>110.1%</td>
<td>$102,434,585</td>
</tr>
<tr>
<td>2008</td>
<td>828,351,283</td>
<td>795,222,167</td>
<td>96.0</td>
<td>110,869,947</td>
</tr>
<tr>
<td>2009</td>
<td>921,349,334</td>
<td>590,044,979</td>
<td>64.0</td>
<td>110,317,579</td>
</tr>
<tr>
<td>2010</td>
<td>952,499,597</td>
<td>660,844,061</td>
<td>69.4</td>
<td>106,590,492</td>
</tr>
<tr>
<td>2011</td>
<td>998,216,259</td>
<td>786,080,314</td>
<td>78.7</td>
<td>108,106,192</td>
</tr>
<tr>
<td>2012</td>
<td>1,046,199,578</td>
<td>766,804,452</td>
<td>73.3</td>
<td>110,037,157</td>
</tr>
<tr>
<td>2013</td>
<td>1,086,925,211</td>
<td>847,232,156</td>
<td>77.9</td>
<td>110,552,014</td>
</tr>
</tbody>
</table>

Other Post-Employment Benefits

The Electric System contributes to two single-employer defined benefit healthcare plans: the Stipend Plan and the Implied Subsidy Plan. These plans provide other post-employment health care benefits (“OPEB”) for eligible retirees and beneficiaries.

The Stipend Plan is available to eligible IBEW retirees and beneficiaries pursuant to their collective bargaining agreement. Benefit provisions for the Stipend Plan are established and amended through the memorandum of understanding with IBEW as approved by the City Council, which currently provides for the Electric System to make contributions on a “pay-as-you-go-basis.” The union establishes the benefits paid to retirees and the City is not required by law or contractual agreement to provide funding for the plan other than as specified in the MOU, which currently provides for a contribution of $50 per month per active IBEW employee.
The Implied Subsidy Plan allows retirees and current employees to be insured together as a group, and allows a lower rate for retirees than if they were insured separately. Upon retirement, retirees pay the full amount of applicable premiums; however, they participate in the Electric System’s healthcare plans and, as such, an implicit subsidy exists. The Riverside Electric System’s contributions to the Implied Subsidy Plan are established by the City Council. The Riverside Electric System is not required by law or contractual agreement to provide funding other than the pay-as-you-go amount necessary to provide current benefits to eligible retirees and beneficiaries.

The Electric System’s annual OPEB cost (expense) for each plan is calculated based on the annual required contribution of the employer (“ARC”), an amount actuarially determined in accordance with the parameters of Governmental Accounting Standards Board Statement No. 45. The ARC represents a level of funding that, if paid on an ongoing basis, is projected to cover normal cost each year and amortize any unfunded actuarial liabilities (or funding excess) over a period not to exceed 30 years. The Electric System’s unfunded OPEB liability as of June 30, 2014 and 2013 was $5,749,000 and $4,928,000, respectively.

Electric System Strategic Plan

Strategic Plan. In October 2001, to adapt to the changing conditions in the electric industry in California, Riverside adopted a comprehensive Strategic Plan.

On November 5, 2004, the Riverside Board agreed to combine the annual strategic planning process with a series of long-term planning workshops, which began in early 2005 and were completed in June 2005. The Strategic Long Range Plan developed ten to twenty year long-term policies and objectives that would provide the framework under which to implement the Riverside Public Utilities Department’s Mission Statement and three-year specific goals.

On November 4, 2011, the Riverside Board held a workshop to update the Ten Year Goals and Vision Statement. As a result, the Riverside Board adopted the following (not in priority order) Ten Year Goals and Vision Statement:

- Employ state-of-the-art technology to maximize reliability and customer service
- Foster economic development and job growth in the City of Riverside
- Communicate effectively the accomplishments, challenges and opportunities for the full utilization of electric and water resources
- Develop fully low-cost, sustainable, reliable electric and water resources
- Enhance the effective and efficient operation of all areas of the utility

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

On February 5, 2014, management held a workshop to update the Three Year Goals and Strategic Plan Objectives. The Three Year Goals (not in priority order) are:

- Contribute to the City of Riverside’s economic development while preserving Riverside Public Utilities’ financial strength
- Maximize the use of technology to improve utility operations
- Impact positively legislation and regulations at all levels of government
• Develop and implement electric and water resource plans
• Create and implement a workforce development plan

To ensure maximum efficiency and improvements in operations, management meets every six to eight months to review/revisit the existing goals/objectives to reflect any substantive changes in the utility operating environment and make adjustments necessary to help achieve the broader strategic goals and objectives. These efforts are reported monthly to the Riverside Board.

**Electric Rates.** Historically, electric rates for Riverside customers have been lower than rates for Edison customers. Based on rates in place as of June 30, 2014, Riverside’s single family residential customers with a monthly average summer consumption of 1,058 kWh would pay an average of 49% higher rates if served by Edison, while single family residential customers with a winter consumption of 648 kWh would pay an average of 16% more if served by Edison. Riverside cannot predict future rate actions with respect to Edison or other utilities.

**Operating Initiatives and Reserves; General Fund Transfer.** Riverside retail revenues from fiscal year June 30, 2010 to June 30, 2014 increased 7% as a result of the three year Electric Utility Rate Plan that was effective January 1, 2008-2010 and positive operating results. Retail revenues were affected during the economic downturn; however, retail revenues are generally increasing year over year due to an increase in retail load, an expanded customer base, and an improving economy. Operating and maintenance costs (excluding depreciation, nuclear fuel and public benefit programs) increased 21% due to power costs, transmission charges and other miscellaneous operating costs. Despite the fact that City Council temporarily suspended rate increases due to economic climate sensitivity, reserves remain healthy.

It is Riverside City Council’s policy to review the General Fund transfer level annually. Since 1999, the General Fund rate has been 9% of prior year’s gross revenues. In fiscal years 2007 and 2008, City Council approved additional transfers of $3 million and $2 million, respectively, and the total transfers in these years were below the maximum authorized by the City Charter. In fiscal year 2010, the City’s General Fund transfer level was increased from 9% to 11.5%, the maximum authorized by the City Charter. The transfer to the General Fund of the City for the fiscal year ended June 30, 2014 was $38.7 million. The General Fund Transfer is funded through the existing rate plan, thus requiring no additional rate adjustments.

The City plans to continue to build cash reserves. The rate increases beginning in 2002 and the three-year electric rate plan approved in December 2006 and revised in December 2007 contributed significantly to improving the City’s reserve requirements and the overall goal to continue to be fiscally sound. At June 30, 2014, operating reserves excluding operating cash was $177.8 million.

**Economic Development and Green Initiatives.** Since Riverside’s 2010 designation as a Silver Certified City in the California Green Communities Challenge, a competition between local governments for community collaboration and conservation, the City has remained committed to environmental issues and serving as a regional leader in sustainability for the State of California. The City has continued its commitment to sustainability with the adoption of its third Green Action Plan in 2012 spearheaded by the Utility.

The Riverside Electric System encourages energy efficient load growth by expanding the use of renewable energy technologies through its solar rebate programs, and continuing to offer aggressive business incentives through a wide variety of cost effective energy efficiency rebate programs. Since 2012, the Riverside Electric System has increased its focus on stimulating small businesses, which comprise over 95% of Riverside’s commercial electric customers. Programs providing the direct
installation of energy and water efficiency measures have benefitted over 3,000 small businesses in Riverside. These energy and water efficiency measures have helped small businesses save nearly a million dollar in utility costs and saved the City over 6 million kWh.

**Power Resource Portfolio Management.** The City manages long-term fuel and power supply risk, renewable resource procurement and compliance with potential state and federal greenhouse gas legislation in an integrated fashion. The 2008 Power Supply Integrated Resource Plan (“IRP”) defines the City’s risk based, long-term plan for providing stable and predictable rates for customers through the procurement of new energy supply sources at reasonable prices.

The City updated its IRP in 2008 and published the approved plan in early 2009. The IRP provides for a future resource portfolio with a higher reliance on renewable resources, especially geothermal resources, City-owned, lower-carbon emitting natural gas generation and an increased emphasis on demand-side management programs. The resource portfolio selection derived from the IRP incorporated the projected impacts of the CAISO’s implementation of MRTU. The IRP provided for 127.5 MW of additional City owned natural gas fired generation by mid-2011 in order to allow the City to meet its local capacity requirement imposed by the CAISO while minimizing environmental impact and cost exposure. This natural gas generation is comprised of the 29.5 MW Clearwater Power Plant (the acquisition of which was completed in September 2010) and the 98 MW expansion at RERC. In late 2012 and through 2013, the City has contracted for a diverse portfolio of renewable resources totaling 211 MW under medium and long term power purchase agreements. This portfolio of renewable resources consists of 86 MW of geothermal resources, 45 MW of wind resources, and 80 MW of solar PV resources. It is anticipated that this portfolio of renewable resources will serve the City’s electric consumption on a least-cost-best-fit basis and will also enable the City in meeting and exceeding the RPS mandate of 33% of the retail electricity energy needs by 2020. With the reconstituted power resource portfolio, the City is likely to have a slightly higher reliance on natural gas in the future and will manage such increased price and supply risk over a one to five-year horizon with hedging contracts using various energy suppliers who have at least an investment grade credit rating.

Riverside recently acquired new modeling software and prepared an updated Integrated Resource Plan. The updated IRP has been presented to the Riverside Board and the Riverside Board will consider adoption of the updated IRP in April or May, 2015. The updated IRP emphasizes the replacement resources for the retired SONGS and the eventual retirement of Intermountain Power Plant by no later than 2027. The updated IRP also analyzes the need for additional local flexible generating resources to enable the integration of increasing amount of intermittent renewable resources.

**Risk Management.** Due to significant changes occurring within California’s electric power industry, management of power resources on a day-to-day basis became critical to the financial stability of an electric utility. In response to these changes, in October 1998, the City Council adopted formal policies for the administration of energy risk management activities within the Resources Division of the Electric System. These policies define the limits for power trading activities to mitigate and reduce risks associated with this business activity. The City also appointed an Energy Risk Manager in 1999 to oversee the development, implementation, and ongoing monitoring of a formalized financial risk management program for power supply activities. Since 1988, the policies have been reviewed on an annual basis and recommended changes have been periodically adopted by the City Council.

Recently, the policies were updated to incorporate changes in regulatory and legislative requirements, including an amendment to authorized transactions, organizational structure, and reporting requirements. The comprehensive updated policies were approved by the Riverside Board and City Council on February 1, 2013 and March 5, 2013, respectively, and include the Energy Risk Management Policy, a Wholesale Counterparty Risk Management Policy and an Authorized Transactions Policy.
APPENDIX B

INTERMOUNTAIN POWER AGENCY AND INTERMOUNTAIN POWER PROJECT

Intermountain Power Agency (“IPA”), a separate legal entity and a political subdivision of the State of Utah, was organized in June 1977, pursuant to the provisions of the Utah Interlocal Co-operation Act, and under the Intermountain Power Agency Organization Agreement, dated May 10, 1977. Its membership consists of 23 municipalities which are suppliers of electric energy in the State of Utah. The purpose of IPA is to own, acquire, construct, operate, maintain and repair any facility or improvement of the Intermountain Power Project (“IPP”).

IPA is governed by its seven-member Board of Directors elected by and from the members’ representatives. The management of IPA is under the direction of its General Manager, who serves at the pleasure of the Board of Directors.

The foregoing description of IPA and the following description of IPP do not purport to cover all aspects of IPA’s operations and financial condition or of IPP. A copy of the most recent IPA annual report and official statement for the issuance of its securities may be obtained from: James A. Hewlett, General Manager, Intermountain Power Agency, 10653 S. River Front Parkway, Suite 120, South Jordan, Utah 84095.

INTERMOUNTAIN POWER PROJECT

General Description

IPP consists of: (a) a two-unit coal-fired, steam-electric generating plant with a net output of 1,800 MW and a switchyard (the “Intermountain AC Switchyard”), located near Lynndyl, in Millard County, Utah (together, the “Intermountain Generating Station”); (b) the Southern Transmission Project (as defined in the front part of this Official Statement); (c) two 50-mile, 345-kV alternating current transmission lines from the Intermountain AC Switchyard to the Mona Switchyard in the vicinity of Mona, Utah, and a 144-mile, 230-kV alternating current transmission line from the Intermountain AC Switchyard to the Gonder Switchyard near Ely, Nevada (collectively, the “Northern Transmission System”); (d) a microwave communications system; (e) a railcar service center located in Springville, in Utah County, Utah (the “Service Center”); and (f) certain water rights and coal supplies. Such water rights and coal supplies, together with the Intermountain Generating Station, the Intermountain AC Switchyard and the Service Center, are referred to herein collectively as the “Generation Station.” All of the above-listed items are herein collectively referred to as the “Project.”

The Project was constructed to provide the IPP Purchasers (as defined below) with firm capacity and energy to satisfy a portion of their projected firm power and energy requirements. July 1, 1986 was the Date of Firm Operation (as such term is defined in the IPP Power Sales Contracts) for Unit 1 of the Project and May 1, 1987 was the Date of Firm Operation for Unit 2 of the Project.

The IPP Purchasers and the IPP Excess Power Sales Agreement

The IPP purchasers are 36 utilities (collectively, the “IPP Purchasers”) consisting of the Department of Water and Power of The City of Los Angeles (the “Department”) and the California cities of Anaheim, Riverside, Burbank, Glendale and Pasadena (the “Project Participants”); Rocky Mountain, an Oregon corporation, as successor to the obligations of Utah Power & Light Company, a Utah corporation, upon the January 1989 merger of the companies (“UP&L”); 22 members of IPA and Heber Light & Power Company (collectively, the “Utah Municipal Purchasers”); and six rural electric cooperatives serving loads in the States of Utah, Arizona, Colorado, Nevada and Wyoming (collectively, the “Cooperative Purchasers”).

Pursuant to the IPP Excess Power Sales Agreement (as amended, the “IPP Excess Power Sales Agreement”), the Utah Municipal Purchasers and the Cooperative Purchasers have sold to the Department and the California Cities of Pasadena, Burbank and Glendale (collectively, the “Excess Power Purchasers”) their entitlements to the use of the capability of the Project except for the portion of such entitlements as to which the Utah Municipal Purchasers or the Cooperative Purchasers have, from time to time, exercised their recall rights under the IPP Excess Power Sales Agreement. So long as no such recall is in effect, the Project Participants are committed to take or pay for 96% of the capability, according to their Power Sales and Excess Power Sales Shares of the Generation Station. The Utah Municipal Purchasers and Cooperative Purchasers may, subject to the lead times and other requirements of the IPP Excess Power Sales Agreement, recall from the Excess Power Purchasers all or any portion of their aggregate 21.057% capability interest in the Generation Station. UP&L is committed to take or pay for the remaining 4% of the capability of the Generation Station, which entitlement UP&L has sold to the Department as described below. As discussed more fully below, certain of the Utah Municipal Purchasers have recalled a portion of their rights to the capability of the Project. While such recall, or any recall that the Utah Municipal Purchasers or Cooperative Purchasers may elect to make hereafter, is in effect, the percentage of the capability of the Generation Station that the Project Participants will be committed to take or pay for shall be reduced by the percentage of capability of the Generation Station that has been recalled, and recalling Utah Municipal Purchasers and/or Cooperative Purchasers will be the only Purchasers committed to take or pay for the percentage of capability so recalled by such Purchasers.

Based on the current schedules of power to be sold under the IPP Excess Power Sales Agreement, which schedules are revised annually: (i) the recalling Utah Municipal Purchasers and the Cooperative Purchasers have committed, subject to certain permitted adjustments, to sell to the Excess Power Purchasers, until March 24, 2015, their Project capability in excess of that which they have recalled and have forecasted that such excess capability will continue to be sold to the Excess Power Purchasers through March 24, 2023 and (ii) the remaining Utah Municipal Purchasers have committed, subject to certain permitted adjustments, to sell to the Excess Power Purchasers, until March 24, 2015, their entire Project capability and have forecasted that such capability will continue to be sold to the Excess Power Purchasers through March 24, 2023.

The following table sets forth, as percentages, the capability of the Generation Station that each California Purchaser, the Utah Municipal Purchasers and the Cooperative Purchasers that have recalled such capability and UP&L are obligated to purchase and pay for from and after September 25, 2012. The table is based on: (i) the percentage UP&L purchases under its IPP Power Sales Contract (without regard to the UP&L/Department Contract discussed below), (ii) the percentage each California Purchaser purchases under its IPP Power Sales Contract and, as to the Excess Power Purchasers, the capability of the Generation Station each is presently committed to purchase under the IPP Excess Power Sales Agreement and (iii) the percentage of capability of the Generation Station that has been recalled by certain of the Utah Municipal Purchasers and the Cooperative Purchasers as described above. Any other recalls that may be effected hereafter will correspondingly decrease the percentages shown below for the
Excess Power Purchasers. The IPP Excess Power Sales Agreement defines a “Winter Season” as each period beginning on September 25 and ending on the following March 24, and a “Summer Season” as each period beginning on March 25 and ending on the following September 24.

Percentages of Capability of Generation Station to be Purchased

<table>
<thead>
<tr>
<th>Power Purchaser</th>
<th>Winter Season beginning 25 Sep 2013</th>
<th>Winter Season beginning 25 Sep 2014</th>
<th>All Other Winter Seasons</th>
<th>Summer Season beginning 25 Mar 2013</th>
<th>Summer Season beginning 25 Mar 2014</th>
<th>All Other Summer Seasons</th>
</tr>
</thead>
<tbody>
<tr>
<td>The Department…………………..</td>
<td>62.687%</td>
<td>62.785%</td>
<td>61.971%</td>
<td>62.785%</td>
<td>62.785%</td>
<td>61.795%</td>
</tr>
<tr>
<td>Pasadena……………………..</td>
<td>5.991</td>
<td>6.000</td>
<td>5.929</td>
<td>6.000</td>
<td>6.000</td>
<td>5.913</td>
</tr>
<tr>
<td>Glendale…………………….</td>
<td>2.203</td>
<td>2.206</td>
<td>2.183</td>
<td>2.206</td>
<td>2.206</td>
<td>2.178</td>
</tr>
<tr>
<td>UP&amp;L………………………….</td>
<td>4.000</td>
<td>4.000</td>
<td>4.000</td>
<td>4.000</td>
<td>4.000</td>
<td>4.000</td>
</tr>
<tr>
<td>Utah Municipal Purchasers…….</td>
<td>0.114</td>
<td>0.000</td>
<td>0.000</td>
<td>0.000</td>
<td>0.000</td>
<td>0.204</td>
</tr>
<tr>
<td>Cooperative Purchasers……..</td>
<td>0.000</td>
<td>0.000</td>
<td>0.944</td>
<td>0.000</td>
<td>0.000</td>
<td>0.944</td>
</tr>
</tbody>
</table>

The Department and UP&L have entered into a Power Purchase Contract (the “UP&L/Department Contract”) pursuant to which: (i) the Department has agreed to purchase from UP&L, and UP&L has agreed to sell to the Department, an amount of capacity equivalent to UP&L’s entitlement in the Project, and associated energy, (ii) UP&L is required to make capacity and energy available to the Department only to the extent of capacity and energy made available to UP&L pursuant to its IPP Power Sales Contract with IPA and (iii) the Department has agreed, whenever either of the units of the Project is available, to schedule an amount of capacity and energy not less than the minimum amounts UP&L is required to schedule pursuant to its IPP Power Sales Contract. Unless otherwise terminated by the parties in accordance with the terms thereof, the term of the UP&L/Department Contract extends until the termination date of the IPP Power Sales Contracts. Under the UP&L/Department Contract, the Department is obligated to pay to UP&L, on a “take or pay” basis, the amounts UP&L is required to pay IPA under its IPP Power Sales Contract. Although the effect of the UP&L/Department Contract is the sale by UP&L to the Department of capacity and energy which is the equivalent of UP&L’s entire entitlement in the Project, the UP&L/Department Contract does not reduce or modify the obligations or rights of UP&L under its IPP Power Sales Contract, and UP&L remains obligated to pay all amounts due thereunder, at the times required thereby.

Contractual Arrangements

IPP Power Sales Contracts. IPA has sold the entire capability of IPP to the 36 IPP Purchasers pursuant to separate IPP Power Sales Contracts between IPA and each IPP Purchaser. Under the IPP Power Sales Contracts, the IPP Purchasers are entitled to IPP generation and transmission capabilities based on their respective Generation Entitlement Shares and transmission entitlements and are obligated to make payments therefor, on a “take or pay” basis, that is, whether or not IPP or any part thereof has been completed, is operating or is operable, or its output is suspended, interrupted, interfered with, reduced or curtailed or terminated in whole or in part, and such payments shall not be subject to reduction whether by offset or otherwise and shall not be conditional upon the performance or nonperformance by any party of any agreement for any cause whatever. The payment obligations under the IPP Power Sales Contracts constitute operating expenses of the respective Project Participants and Utah Municipal Purchasers, payable solely from their electric revenue funds, and general obligations of UP&L and the respective Cooperative Purchasers.
**IPP Excess Power Sales Agreement.** Since a portion of the capability of IPP purchased by the Utah Municipal Purchasers and the Cooperative Purchasers was expected to be surplus to their needs, each of these IPP Purchasers entered into an IPP Excess Power Sales Agreement. The IPP Excess Power Sales Agreement does not reduce or modify the obligations of such Utah Municipal Purchasers and Cooperative Purchasers under their IPP Power Sales Contracts. See “The IPP Purchasers and the IPP Excess Power Sales Agreement.”

**Delivery of Project Output**

The output of the Project is delivered to the IPP Purchasers at points of delivery designated by them from among the Intermountain AC Switchyard, the Mona and Gonder Switchyards of the Northern Transmission System, and the Adelanto Converter Station of the Southern Transmission Project. Each of the IPP Purchasers is responsible for providing for transmission of its entitlement of Intermountain Generating Station output from its designated point of delivery to its electric system.

The Adelanto Converter Station is connected with the Department’s main transmission system, and the Department takes delivery of its entitlement of Intermountain Generating Station output at the Adelanto Converter Station. The other Project Participants also have designated the Adelanto Converter Station as their point of delivery, and transmission services for such other Project Participants to their electric systems are provided by the Department for the Cities of Glendale and Burbank and by the Department and California Independent System Operator for the Cities of Anaheim, Riverside and Pasadena. Both the Adelanto Converter Station and the Mead-Adelanto Transmission Project are connected to the Adelanto Switching Station.

The IPP Power Sales Contracts permit any Purchasers other than UP&L to provide to UP&L any portion of their transmission entitlement capacity shares over portions of the Northern Transmission System by appropriate arrangements. Such Purchasers have responsibility to notify the Department, as Project Manager and Operating Agent, of the arrangements and to provide proper schedules to furnish UP&L with its entitlement to Intermountain Generating Station output.

UP&L will provide transmission services for the Utah Municipal Purchasers and the Cooperative Purchasers, except: (i) Mt. Wheeler Power, Inc. (which has designated the Gonder Switchyard as its point of delivery and takes delivery of its power from other sources at that point) and (ii) Moon Lake Electric Association, Inc. (which has made arrangements to use facilities that have been constructed by Deseret Generation & Transmission Co-operative in connection with its Bonanza project).

**Management of Construction and Operation**

The design, construction, operation and maintenance of IPP have been or are being managed for IPA by the Department in its capacity as Project Manager and Operating Agent under the Construction Management and Operating Agreement.

The Department fulfills its obligation with respect to the operation and maintenance of the Intermountain Generating Station, the Intermountain Converter Station and the Railcar Service Center through the use of the personnel of the Intermountain Power Service Corporation (“IPSC”), a private non-profit corporation jointly governed by the Department and IPA. The International Brotherhood of Electrical Workers has been certified as the collective bargaining representative of certain of the employees of IPSC. The current collective bargaining agreement between these parties expires on June 30, 2015. The Department fulfills its obligations with respect to the operation and maintenance of the remaining Project facilities through its own personnel.
**IPP Coordinating Committee**

Pursuant to the IPP Power Sales Contracts, the IPP Coordinating Committee, among other functions, provides liaison among IPA and the IPP Purchasers with respect to the construction and operation of the Project, reviews, modifies and approves certain specified contracts, takes certain actions with respect to actions of the Department, as Project Manager and Operating Agent, and makes recommendations to IPA regarding the financing and refinancing of the Project. The IPP Coordinating Committee also has authority to review, modify and approve procedures formulated by the Project Manager and Operating Agent with respect to the construction and operation of the Project, budgets prepared by the Project Manager and Operating Agent, and all capital improvements proposed to be undertaken by IPA.

The IPP Coordinating Committee consists of the Chairman, who is a non-voting representative appointed by IPA, and representatives of the IPP Purchasers or groups thereof. The Chairman of the IPP Coordinating Committee may, at his own discretion, and must, at the request of any member of the Committee, call a meeting of the Committee. All actions taken by the Committee require the affirmative vote of representatives of IPP Purchasers having voting rights (which equal the respective IPP Purchasers’ current Generation Entitlement Shares) aggregating at least 80%.

The IPP Coordinating Committee presently consists of its Chairman (the General Manager of IPA) and the following voting representatives:

<table>
<thead>
<tr>
<th>Power Purchaser(s) Represented</th>
<th>Representative</th>
<th>Voting Rights Percentage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Murray City</td>
<td>Blaine Haacke</td>
<td>4.000%</td>
</tr>
<tr>
<td>Logan City</td>
<td>Russell F. Fjeldsted</td>
<td>2.469%</td>
</tr>
<tr>
<td>All Other Utah Municipal Purchasers</td>
<td>Ted L. Olsen</td>
<td>7.571%</td>
</tr>
<tr>
<td>Moon Lake Electric Association, Inc.</td>
<td>Grant J. Earl</td>
<td>2.000%</td>
</tr>
<tr>
<td>Mt. Wheeler Power, Inc.</td>
<td>Randy Ewell</td>
<td>1.786%</td>
</tr>
<tr>
<td>All Other Cooperative Purchasers</td>
<td>Carl R. Albrecht</td>
<td>3.231%</td>
</tr>
<tr>
<td>UP&amp;L</td>
<td>Shane Holst</td>
<td>4.000%</td>
</tr>
<tr>
<td>City of Anaheim</td>
<td>Dukku Lee</td>
<td>13.225%</td>
</tr>
<tr>
<td>City of Burbank</td>
<td>Ronald E. Davis</td>
<td>3.371%</td>
</tr>
<tr>
<td>City of Glendale</td>
<td>Stephen M. Zurn</td>
<td>1.704%</td>
</tr>
<tr>
<td>City of Pasadena</td>
<td>Phyllis Currie</td>
<td>4.409%</td>
</tr>
<tr>
<td>City of Riverside</td>
<td>Girish Balachandran</td>
<td>7.617%</td>
</tr>
<tr>
<td>Department of Water and Power of The City of Los Angeles</td>
<td>Michael S. Webster</td>
<td>44.617%</td>
</tr>
</tbody>
</table>

**Fuel Supply**

During fiscal year 2013-14, Unit 1 operated at a plant capacity factor of 74.55% and Unit 2 operated at a plant capacity factor of 82.20%.

Coal consumption during fiscal year 2013-14 was approximately 5.4 million tons. The Operating Agent manages a diversified portfolio of coal supply agreements that provide for the coal requirements of the Generation Station. The Operating Agent has determined that coal presently under contract is sufficient, with the exercise of available options, to meet the Generation Station’s annual coal requirements through 2016, with lesser amounts of coal under contract for an additional year thereafter. Additional coal will be purchased through a combination of long-term and spot contracts. The average
cost of coal delivered to the Intermountain Generating Station in fiscal year 2013-14 was approximately $47.53 per ton. During fiscal year 2012-13, the average cost of coal delivered was approximately $47.62 per ton.

To be able to continue to operate the Project in the event of a disruption in the Project’s coal supply, IPA attempts to maintain a coal stockpile at the Intermountain Generating Station that is sufficient to operate the plant at current plant capacity factors for about 60 days.

Transportation of coal to the Intermountain Generating Station is provided primarily by rail under agreements between the IPA and the Utah Railway and the Union Pacific Railroad companies, and the coal is transported primarily in IPA-owned railcars. Coal can also be transported, to some extent, in commercial trucks.

**Water Supply**

IPA owns off-site water rights (primarily from the Sevier River) that yield approximately 45,000 acre-feet per year. This amount exceeds the annual water requirements of the Intermountain Generating Station and the Intermountain Converter Station. A reservoir at the Intermountain Generating Station, in combination with ground-water wells, can provide sufficient water to operate for approximately three months at average plant loads.

**Permits, Licenses and Approvals**

IPA believes that the Project has been designed, constructed and operated in compliance with all applicable federal, state and local regulations, codes, standards and laws. All principal permits, licenses and approvals required to construct and operate the Project have been acquired, including permits relating to air quality and rights-of-way on federally-owned land.

**Environmental Matters**

*Emissions.* The Intermountain Generating Station’s boiler and flue-gas cleaning facilities have been designed and constructed to meet applicable Federal and state emission regulations. The boilers have been designed to meet stringent regulatory emission limits for oxides of nitrogen. The flue-gas desulfurization equipment (scrubber) for each unit consists of a wet scrubber system using a limestone reagent designed and constructed to remove at least 90% of the sulfur dioxide before discharge to the atmosphere from a chimney 710 feet in height. The flue-gas particulate control (baghouse) equipment for each unit consists of three modular fabric filters utilizing reverse air for cleaning. The equipment has been designed and constructed to remove at least 99.75% of the particulate material.

*Waste Management.* Substantial federal, state and local legislation and regulations regarding various aspects of waste management are in effect. Federal laws as set forth in acts such as the Federal Resource Conservation and Recovery Act and the Comprehensive Environmental Response, Compensation and Liability Act, as amended by the Superfund Amendments and Reauthorization Act, impose strict liability for cleanup costs and damages regardless of time or location on generators, transporters, storers and disposers of hazardous waste. Many day-to-day activities connected with the generation and transmission of electricity generate both non-hazardous and hazardous wastes. IPSC, under the direction of the Department, has established a waste management program for the Project. The program is designed to assure that the Project’s present and future operations conform to applicable waste disposal regulations. The Department has also assessed Project properties for potential liability arising from past, latent contamination. The Department has indicated that its waste management program complies with all federal, state and local statutes and guidelines and all applicable permit requirements.
Operating Information

Operating Experience. The Project facilities have operated to date with a high degree of availability, exceeding the average of coal-fired generating units of comparable size. Neither the IPA nor the Operating Agent is aware of any operational or equipment problems that would materially and adversely affect future operations on a long-term basis.

Operating Statistics. The operating results of the Project during fiscal years 2009-2010 through 2013-2014 are shown in the following table. Based on the historical experience of comparable generating units, the Project is expected to continue to achieve on a long-term basis the above-average levels of performance demonstrated to date.

[Balance of the page intentionally left blank.]
## Operating Statistics

<table>
<thead>
<tr>
<th>Gross Energy Generated (MWh)</th>
<th>Fiscal Year 2009-10(1)</th>
<th>Fiscal Year 2010-11(2)</th>
<th>Fiscal Year 2011-12(3)</th>
<th>Fiscal Year 2012-13(4)</th>
<th>Fiscal Year 2013-14(5)</th>
<th>Industry Average Calendar Years 2009-2013(6)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Unit 1</td>
<td>7,630,681</td>
<td>6,395,266</td>
<td>4,469,859</td>
<td>6,813,173</td>
<td>6,248,418</td>
<td>5,358,134</td>
</tr>
<tr>
<td>Unit 2</td>
<td>7,693,067</td>
<td>6,056,456</td>
<td>7,038,500</td>
<td>5,842,280</td>
<td>6,898,997</td>
<td>5,358,134</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Net Energy Generated (MWh)</th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Unit 1</td>
<td>7,181,029</td>
<td>5,994,625</td>
<td>4,190,369</td>
<td>6,409,168</td>
<td>5,877,465</td>
<td>5,060,658</td>
</tr>
<tr>
<td>Unit 2</td>
<td>7,237,935</td>
<td>5,670,017</td>
<td>6,603,073</td>
<td>5,475,553</td>
<td>6,480,413</td>
<td>5,060,658</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Plant Capacity Factor(7)</th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Unit 1</td>
<td>91.08%</td>
<td>76.04%</td>
<td>53.01%</td>
<td>81.29%</td>
<td>74.55%</td>
<td>69.03%</td>
</tr>
<tr>
<td>Unit 2</td>
<td>91.81%</td>
<td>71.92%</td>
<td>83.52%</td>
<td>69.45%</td>
<td>82.20%</td>
<td>69.03%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Operating Availability(8)</th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Unit 1</td>
<td>97.85%</td>
<td>87.11%</td>
<td>58.67%</td>
<td>96.07%</td>
<td>86.06%</td>
<td>84.82%</td>
</tr>
<tr>
<td>Unit 2</td>
<td>99.15%</td>
<td>82.97%</td>
<td>96.81%</td>
<td>83.66%</td>
<td>97.86%</td>
<td>84.82%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Equivalent Availability(9)</th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Unit 1</td>
<td>97.30%</td>
<td>82.70%</td>
<td>58.16%</td>
<td>95.62%</td>
<td>85.99%</td>
<td>83.03%</td>
</tr>
<tr>
<td>Unit 2</td>
<td>98.55%</td>
<td>80.07%</td>
<td>96.57%</td>
<td>82.96%</td>
<td>97.78%</td>
<td>83.03%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Net Unit Heat Rate (BTU/kWh)(10)</th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Unit 1</td>
<td>9,560</td>
<td>9,724</td>
<td>9,643</td>
<td>9,633</td>
<td>9,632</td>
<td>10,511</td>
</tr>
<tr>
<td>Unit 2</td>
<td>9,601</td>
<td>9,941</td>
<td>9,963</td>
<td>9,943</td>
<td>9,745</td>
<td>10,511</td>
</tr>
</tbody>
</table>

---

(1) Reflects the following 2009-10 scheduled maintenance outage: Unit 1 Spring 2010 (7 days). The Major Maintenance Outage on Unit 2 originally scheduled for Spring 2010 was postponed until Fall 2010 resulting in no Major Maintenance Outage on Unit 2 during the 2009-10 fiscal year.

(2) Reflects the following 2010-11 scheduled maintenance outage: Unit 2 Fall 2010 (6 weeks); and Unit 1 Spring 2011 (6 weeks) resulting in two Major Maintenance Outages during the 2010-2011 fiscal year.

(3) Reflects the following 2011-12 scheduled maintenance outage: Unit 1 Spring 2012 (21.6 weeks), consisting of a forced outage of 151 days commencing on December 28, 2011; and Unit 2 Spring 2012 (5.4 days). The forced outage of Unit 1 was handled as a maintenance outage to make required repairs.

(4) Reflects the following 2012-13 scheduled maintenance outage: Unit 2 Spring Major 2013 (6 weeks) and Unit 1 Spring Minor (7 days).

(5) Reflects the following 2013-14 scheduled maintenance outage: Unit 1 Spring Major 2014 (6 weeks) and Unit 2 Spring Minor (7 days).

(6) Industry average figures except heat rate are as reported by NERC for coal-fired units rated 800-999 MW and are the composite averages of 40 units in the years 2009 through 2013. Average net station heat rate is compiled and cited from Form EIA-923 released by the Energy Information Administration of the U.S. Department of Energy for 2013 for the top 25 largest western coal-fired power plants.

(7) The Plant Capacity Factor for a unit is the ratio of the net energy generated by that unit to the net maximum capability of that unit times the hours in the period and reflects the unit availability as well as the actual power produced by the unit.

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

(9) The Equivalent Availability Factor provides an adjustment of the Operating Availability by incorporating the effect of deratings (losses in MW capability) and is essentially equivalent to the percentage of time during a period during which a unit was available for maximum net capability operation.

(10) The Unit Heat Rate is a measure of the efficiency of the unit and shows the amount of heat energy in BTUs necessary to produce 1.0 net kWh. The smaller this number is, the more efficient the unit.
Cost of IPP Power and Cost Reduction Activities

The average cost of IPP power and energy delivered at the Intermountain Generating Station during IPA’s 2013-14 fiscal year was approximately $53.24 per MWh. This cost does not include the cost of transmission over the Southern Transmission Project or the Northern Transmission Project. IPA and the IPP purchasers continue to work towards minimizing IPP costs.

IPP has been financed entirely with debt. Debt service (net of projected investment earnings) constitutes in excess of 50% of IPA’s total annual costs of owning, operating and maintaining IPP and is the major factor in IPP’s power and energy costs.

IPA and the Project Participants have developed a debt restructuring plan to make the cost of power and energy from IPP more competitive by accelerating the retirement of Project debt. To accomplish this acceleration, IPA and the Project Participants have entered into a “Prepayment Agreement.” The Department made prepayments to IPA during the 2000 and 2005 calendar years which have been applied by IPA, pursuant to the direction of the Department, to prepay, defease or purchase on the open market and cancel senior indebtedness in the aggregate principal amount of approximately $1.5 billion under the Prepayment Agreement.
[THIS PAGE INTENTIONALLY LEFT BLANK]
SUMMARY OF CERTAIN DOCUMENTS

TABLE OF CONTENTS

Summary of Certain Provisions of the Senior Indenture ............................................................. C-1
Summary of Certain Provisions of the 2015 Series C Subordinated Indenture .................................. C-10
Summary of Certain Provisions of the Transmission Service Contracts ....................................... C-26
Summary of Certain Provisions of the IPP Power Sales Contracts ............................................... C-33
Summary of Certain Provisions of the Agreements for the Acquisition of Capacity ..................... C-37
Summary of Certain Provisions of the Southern Transmission System Agreement ....................... C-39

SUMMARY OF CERTAIN PROVISIONS OF THE SENIOR INDENTURE

The following is a summary of certain provisions of the Senior Indenture. This summary is not to be considered a full statement of the terms of the Senior Indenture and accordingly is qualified by reference thereto and is subject to the full text thereof. Capitalized terms not defined in this summary or in the Official Statement have the respective meanings set forth in the Senior Indenture.

Definitions

Adjusted Aggregate Debt Service means, as of any date of calculation and with respect to any period, the sum of (i) the sum of the amounts of Adjusted Debt Service during such period for all Series of Senior Bonds and (ii) the Aggregate Debt Service during such period for all Series of Senior Bonds not included in the computation of Adjusted Debt Service on such date of calculation; provided, however, that in computing such Aggregate Debt Service any particular Lender Bonds shall be deemed to bear at all times to the maturity thereof the Assumed Interest Rate applicable thereto.

Adjusted Debt Service means, with respect to any Series of Senior Bonds, as of any date of calculation and with respect to any period, the Debt Service for such Series of Senior 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 Senior Bonds of such Series would have Substantially Equal Debt Service (as defined below) for each Fiscal Year of such period and so that such Principal Installment would be fully paid at the end of such period, assuming timely payment of all principal of and premium, if any, and interest on the Senior 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 Senior Bonds (determined by the true, actuarial method of calculation). Such adjustment shall be made over a period which shall begin with the final maturity date of such Series and end on a date which shall be specified in the Supplemental Indenture of Trust authorizing such Series of Senior Bonds, which date shall be not later than the earlier to occur of (i) 35 years after the date of such Senior Bonds or (ii) the termination date of the Transmission Service Contracts. For purposes of computing such true interest cost for any Series of Senior Bonds containing Lender Bonds, each such Lender Bond shall be deemed to bear at all times to the maturity date thereof the Assumed Interest Rate applicable thereto.
Assumed Interest Rate means, as to any Lender Bonds with a Variable Interest Rate, the interest rate for such Senior Bonds assumed for purposes of determining their maturity schedule, and as to any Lender Bonds not having a Variable Interest Rate, the stated interest rate for each such Lender Bond.

Cap Agreement means any financial arrangement which has been designated in writing to the Senior Indenture Trustee by an Authorized Authority Representative as a Cap Agreement under the Senior Indenture.

Debt Service Reserve Requirement means $0.

Lender Bonds mean Bonds which: (i) are issued in exchange for Notes, (ii) are issued pursuant to requirements of a lending or credit facility or agreement, and (iii) will be held by a bank, trust company or similar financial institution, domestic or foreign.

Series shall mean all of the Bonds authenticated and delivered on original issuance and identified pursuant to the Senior Indenture or the Supplemental Indenture of Trust authorizing such Bonds as a separate Series of Bonds, and any Bonds thereafter authenticated and delivered in lieu of or in substitution for such Bonds pursuant to the Senior Indenture, regardless of variations in maturity, interest rate, sinking fund installments, or other provisions.

Substantially Equal Adjusted Aggregate Debt Service means, with respect to any period of similar Fiscal Years for all Series of Senior 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 per cent 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 Years for any Series of Senior Bonds, that the greatest Debt Service for any Year in such period is not in excess of one hundred and twenty-five per cent of the smallest Debt Service for any Year in such period; provided, however, that in computing Debt Service for the purpose of this definition, any particular Lender Bond shall be deemed to bear at all times prior to maturity thereof the Assumed Interest Rate applicable thereto.

Pledge Effected by the Senior Indenture

Under the Senior Indenture, the Authority has pledged and assigned to the Senior Indenture Trustee, for the benefit of the Holders of the Senior Bonds (the “Senior Bondholders”), (1) the proceeds of the sale of the Senior Bonds, (2) the Revenues, and (3) all Funds established by the Senior Indenture including the investments, if any, thereof, subject only to the provisions of the Senior Indenture permitting the application thereof for the purposes and on the terms and conditions set forth in the Senior Indenture (including application of the moneys on deposit in the escrow funds established under the Senior Indenture).

Application of Revenues

Revenues are pledged by the Senior Indenture to payment of the principal and Redemption Price of, and interest on, the Senior Bonds, subject to the provisions of the Senior Indenture permitting application for other purposes. The Senior Indenture establishes the following Funds and Accounts for the application of Revenues:
Funds Held By

<table>
<thead>
<tr>
<th>Funds</th>
<th>Held By</th>
</tr>
</thead>
<tbody>
<tr>
<td>Construction Fund</td>
<td>Senior Indenture Trustee</td>
</tr>
<tr>
<td>Revenue Fund</td>
<td>Senior Indenture Trustee</td>
</tr>
<tr>
<td>Operating Fund</td>
<td>Senior Indenture Trustee</td>
</tr>
<tr>
<td>Debt Service Fund</td>
<td>Senior Indenture Trustee</td>
</tr>
<tr>
<td>- Debt Service Account</td>
<td>Senior Indenture Trustee</td>
</tr>
<tr>
<td>- Debt Service Reserve Account</td>
<td>Senior Indenture Trustee</td>
</tr>
<tr>
<td>Bond Anticipation Note Fund</td>
<td>Senior Indenture Trustee</td>
</tr>
<tr>
<td>Reserve and Contingency Fund</td>
<td>Senior Indenture Trustee</td>
</tr>
<tr>
<td>- Renewal and Replacement Account</td>
<td>Senior Indenture Trustee</td>
</tr>
<tr>
<td>- Reserve Account</td>
<td>Senior Indenture Trustee</td>
</tr>
<tr>
<td>General Reserve Fund</td>
<td>Senior Indenture Trustee</td>
</tr>
</tbody>
</table>

* The Senior Indenture was amended in April 2001, with the consent of Holders of the Senior Bonds, to eliminate the Debt Service Reserve Requirement for the Senior Bonds.

All 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 Fund, a sum which, together with any amount in the Operating Fund not set aside as a general reserve for Authority Operating Expenses or as a reserve for working capital, is equal to the total moneys appropriated for Authority Operating Expenses in the Annual Budget for the then current month. Such sum shall be paid to the Operating Fund as soon as practicable in each month after deposit of Revenues in the Revenue Fund, but not later than the last business day of such month. In addition, if the Supplemental Indenture authorizing a Series of Senior 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. At the requisition of the Authority, signed by two Authorized Authority Representatives, amounts in the Operating Funds shall be paid out from time to time by the Senior Indenture Trustee for reasonable and necessary Authority Operating Expenses. Additional amounts may be paid out from the Operating Fund to establish a revolving fund with a maximum balance of $250,000 for the payment of Authority Operating Expenses not conveniently paid as described in the previous sentence. The Senior Indenture provides for the application of excess amounts in the Operating Fund to make up any deficiencies in certain other funds established under the Senior Indenture with any balance to be deposited in the General Reserve Fund.

2. To the Debt Service Account in the Debt Service Fund, the amount required so that the balance in such Account equals the Accrued Aggregate Debt Service. The Senior Indenture Trustee shall apply amounts in the Debt Service Account to the payment of principal of and interest on the Senior Bonds; provided, however, that the interest coming due with respect to any Series of Senior Bonds may be payable by the Senior Indenture Trustee in such other manner as the Supplemental Indenture of Trust authorizing such Series of Senior Bonds shall specify. In addition, the Senior Indenture Trustee may, and if directed by the Authority must, apply certain amounts in the Debt Service Account to the purchase or redemption of Senior Bonds to satisfy sinking fund requirements prior to the due date of any Sinking Fund Installment. The Senior Indenture Trustee must pay out of the Debt Service Account the amount required for the
redemption of Senior Bonds called for redemption pursuant to sinking fund requirements, or the amount maturing on any redemption or maturity date.

In the event of the refunding of one or more Series of Senior Bonds, the Senior Indenture Trustee shall, upon the direction of the Authority with the advice of Bond Counsel, withdraw from the Debt Service Account in the Debt Service Fund amounts accumulated therein with respect to Debt Service on the Senior Bonds being refunded and hold such amounts for the payment of the principal or Redemption Price, if applicable, and interest on the Series of Senior Bonds being refunded; provided that such withdrawal shall not be made unless: (1) immediately thereafter the Series of Senior Bonds being refunded shall be deemed to have been paid pursuant to the Senior Indenture; and (2) the amount remaining in the Debt Service Account after such withdrawal shall not be less than the requirement of such Account pursuant to the Senior Indenture.

3. To the Bond Anticipation Note Fund, the amount, if any, required so that the balance in said Fund together with the amount on deposit in any fund established pursuant to the proceedings authorizing the Notes and lawfully available to pay interest on outstanding Notes accrued and unpaid and to accrue to the end of the then current calendar month shall equal all interest on outstanding Notes accrued and unpaid and to accrue to the end of the then current calendar month. The Senior Indenture Trustee shall apply amounts in the Bond Anticipation 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 Account are less than the amounts required by the Senior Indenture, and there is not on deposit in the General Reserve Fund or in the Renewal and Replacement Account or the Reserve Account in the Reserve and Contingency Fund available moneys sufficient to cure such deficiency, the Senior Indenture Trustee shall transfer from the Bond Anticipation Note Fund the amount necessary to make up such deficiency.

4. 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, provided for deposit therein during the then current month in the current Annual Budget.

Amounts in the Renewal and Replacement Account shall be applied to the Cost of Acquisition of Capacity relating to any 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 Senior Bonds, amounts in the Reserve Account shall be applied to the payment of extraordinary operation and maintenance costs and contingencies of the Transmission Project. No payments shall be made from the Reserve and Contingency Fund if and to the extent that the proceeds of insurance, including the proceeds of any self-insurance fund, or other moneys recoverable as the result of damage, if any, are available to pay the costs otherwise payable from the Reserve and Contingency Fund.

If at any time the amounts in the Debt Service Account are less than the amounts required by the Senior Indenture, and there are not on deposit in the General Reserve Fund available moneys sufficient to cure such deficiency, then the Senior Indenture Trustee shall 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 in 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 the Authority, to make up any deficiencies therein. Any remaining excess shall be deposited into the General Reserve Fund.

5. To the General Reserve Fund, the balance, if any, in the Revenue Fund. The Authority must transfer from the General Reserve Fund amounts in the following order of priority: (a) to the Debt Service Account and the Debt Service Reserve Account in the Debt Service Fund the amount necessary (or all the moneys in the General Reserve Fund if less than the amount necessary) to make up any deficiencies in required payments to said Accounts; and (b) to the Renewal and Replacement Account and the Reserve Account in the Reserve and Contingency Fund the amount necessary (or all the moneys in the General Reserve Fund if less than the amount necessary) to make up any deficiencies in required payments to said Accounts.

Deposits from the Revenue Fund into the Debt Service Fund, the Bond Anticipation Note Fund, the Reserve and Contingency Fund and the General Reserve Fund shall be made as soon as practicable in each month after the deposit of revenues into the Revenue Fund and the payment to the Operating Fund have been made for such month, but not later than the last business day of such month.

Amounts in the General Reserve Fund not required to meet any of the deficiencies described above or not required by the Senior Indenture for the purchase or redemption of Senior Bonds or not required to be transferred to the 2015 Series C Pledged Revenues Account pursuant to the 2015 Series C Subordinated Indenture, 2015 Series A and B Pledged Revenues Account pursuant to the 2015 Series A and B Subordinated Indenture, 2013 Series A and B Pledged Revenues Account pursuant to the 2013 Subordinated Indenture, the 2012 Series A Pledged Revenues Account pursuant to the 2012 Subordinated Indenture, the 2011 Series A Pledged Revenues Account pursuant to the 2011 Subordinated Indenture, the 2009 Series A Pledged Revenues Account pursuant to the 2009 Subordinated Indenture, the 2008 Series A Pledged Revenues Account pursuant to the 2008 Series A Subordinated Indenture or to the 1992 Pledged Revenues Account pursuant to the 1992 Subordinated Indenture, will, upon determination of the Authority, be applied to or set aside for any one or more of the following: (i) payment into the Revenue Fund; (ii) the purchase or redemption of any Senior Bonds, and expenses and reserves in connection therewith; (iii) Authority Operating Expenses or reserves therefor; (iv) payments into any separate account or accounts established in the Construction Fund; (v) Cost of Acquisition of Capacity attributable to Capital Improvements or reserves therefor; (vi) reduction of the monthly transmission costs of the Project Participants under the Transmission Service Contracts; (vii) payment of principal of Notes; and (viii) any other lawful purpose of the Authority related to the Transmission Project or the Authority Capacity. Senior Bonds purchased or redeemed with amounts in the General Reserve Fund shall be credited to Sinking Fund Installments thereafter to become due (other than the next due).

Certain Requirements of and Conditions to Issuance of Senior Bonds

Senior Bonds shall be authenticated by the Senior Indenture Trustee pursuant to the Senior Indenture upon compliance with certain requirements and conditions, including the following:

(a) The Senior Indenture Trustee shall have received an Opinion of Bond Counsel to the effect that the Senior Bonds of the Series being issued have been duly and validly authorized and issued and are valid and binding obligations of the Authority and as to certain other matters concerning the Senior Indenture.
(b) Except in the case of Lender Bonds and Refunding Bonds, the Authority shall have certified that it is not in default in the performance of its agreements under the Senior Indenture.

The Senior Indenture also provides that Principal Installments shall be established at the time of issuance for each Series of Senior Bonds and each Series of Additional Bonds and Refunding Bonds so as to comply with the following:

(a) Such Principal Installment shall commence not later than the later of (i) the first day of the eighth Fiscal Year following the end of the Fiscal Year of authentication and delivery of such Series of Senior Bonds or (ii) the first day of the fifth Fiscal Year following the end of the Fiscal Year in which the Authority estimates that the Initial Facilities will first reach their Date of Firm Operation and shall terminate not later than the date on which the Transmission Service Contracts terminate.

(b) Such Principal Installments shall result in either (i) Substantially Equal Debt Service for the Senior Bonds of such Series for the Year immediately preceding the due date of the first such Principal Installment to occur subsequent to the Date of Firm Operation of the Initial Facilities and for each Year thereafter to and including the final maturity date of such Series or (ii) Substantially Equal Adjusted Aggregate Debt Service for all Outstanding Senior Bonds, including such Series being issued, for the first Fiscal Year in which Principal Installments become due on all Series of Senior 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 Initial Facilities, and for each Fiscal Year thereafter to and including the Fiscal Year immediately preceding the latest maturity of any Series of Senior 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 Senior Bonds sold by competitive bidding a net effective interest rate for the Senior Bonds of such Series as estimated by the Authority); provided, that, if the first Principal Installment for any Series of Senior 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 Senior Bonds was Outstanding.

Additional Bonds

The Authority may issue one or more Series of Additional Bonds for the purpose of paying all or a portion of the Cost of Acquisition of Capacity relating to any Capital Improvements.

Refunding Bonds

One or more Series of Refunding Bonds may be issued to refund any Outstanding Senior Bonds of one or more Series or one or more maturities within a Series. Refunding Bonds shall be authenticated and delivered by the Senior Indenture Trustee pursuant to the Senior Indenture upon compliance with certain requirements and conditions, including the receipt by the Senior Indenture Trustee of either (i) moneys sufficient to pay the applicable Redemption Price of the refunded Senior Bonds to be redeemed plus the amount required to pay principal on refunded Senior Bonds not to be redeemed together with accrued interest on such Senior 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 Senior Indenture Trustee.
Indenture to pay the principal or Redemption Price, if applicable, and interest due on the redemption date or maturity date, as the case may be.

Investment of Certain Funds and Accounts

The Senior Indenture provides that certain Funds and Accounts held thereunder may, and in the case of the Debt Service Account in the Debt Service Fund and in the case of the Bond Anticipation Note Fund, subject to the terms of agreements relating to the issuance of Notes, shall, be invested and re-invested to the fullest extent practicable in Investment Securities. The Senior Indenture provides that such investments and re-investments will mature no later than such times as are necessary to provide moneys when needed for payments from such Funds and Accounts and provides specific limitations on the term of investments for moneys in certain Funds and Accounts.

Interest (net of that which (i) represents a return of accrued interest paid in connection with the purchase of any investment and (ii) is required to offset the amortization of any premium paid in connection with the purchase of any investment) earned on any moneys or investments in such Funds or Accounts, other than the Construction Fund, shall be paid into the Revenue Fund except that interest shall be paid into the Construction Fund to the extent provided in the Supplemental Indenture of Trust authorizing any Series of Senior Bonds issued under the Senior Indenture. Interest earned on any moneys or investments in each separate account in the Construction Fund shall be held in such account for the purposes thereof.

The Senior Indenture Trustee may deposit moneys in all Funds and Accounts held under the Senior 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 Senior Indenture by the Senior Indenture 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 depositing with the Senior Indenture 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 Securities” in the Senior Indenture having a market value (exclusive of accrued interest) not less than the amount of such moneys, and (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 Senior Indenture Trustee 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 of or interest on any Senior Bonds or to give security for any moneys which shall be represented by obligations or certificates of deposit purchased as an investment of such moneys.

In computing the amount in any Fund created under the Senior Indenture, obligations purchased as an investment of moneys therein shall be valued at the amortized cost of such obligations or the market value thereof, whichever is lower, exclusive of accrued interest. Such computations shall be determined as of July 1 in each year.

Rate Covenant

The Authority covenants in the Senior Indenture as long as any Senior Bonds are Outstanding it will have good right and lawful power to establish and collect rates and charges with respect to the use of Authority Capacity, subject to the terms of the Transmission Service Contracts. The Authority covenants in the Senior Indenture that it shall at all times establish and collect rates and charges for the use of Authority Capacity which provide Revenues at least sufficient in each Fiscal Year, together with other available funds, for the payment of all of the following:
(a) Authority 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 Bond Anticipation Note Fund;
(d) 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
(e) All other charges or liens whatsoever payable out of Revenues during such Fiscal Year.

The Authority will not furnish or supply or cause to be furnished or supplied any use or service of Authority Capacity free of charge to any person, firm or corporation, public or private, and the Authority will, subject to the Senior Indenture and consistent with the Transmission Project Agreements, and upon the direction of the Senior Indenture Trustee, enforce the payment of any and all accounts owing to the Authority by reason of Authority Capacity by discontinuing such use or service, or by filing suit therefor, as soon as practicable 90 days after any such accounts are due, or by both such discontinuance and by filing suit.

Covenants with Respect to Transmission Service Contracts and Transmission Project Agreements

The Senior Indenture Trustee covenants that it shall receive and deposit in the Revenue Fund all amounts payable to it under the Transmission Service Contracts or otherwise payable to it pursuant to any contract for use of Authority Capacity or any part thereof. The Authority shall enforce the provisions of the Transmission Service Contracts and duly perform its covenants and agreements thereunder, and 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 Transmission Service Contracts which would reduce the payments required thereunder or which would in any manner materially impair or materially adversely affect the rights of the Authority thereunder or the rights or security of Bondholders under the Senior Indenture; however, the Authority is not thereby prohibited from amending any Transmission Service Contracts.

The Authority shall enforce the provisions of the Transmission Project Agreements and duly perform its covenants and agreements thereunder. The Authority 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 Transmission Project Agreements which will in any manner materially impair or materially adversely affect the rights of the Authority thereunder or the rights or security of the Bondholders under the Senior Indenture; however, the Authority is not thereby prohibited from amending or taking other action in connection with any Transmission Service Contracts, Southern Transmission System Agreement, Power Sales Contract or Intermountain Power Agency’s Bond Resolution.

Insurance

The Authority shall, at all times after it shall acquire Authority Capacity, insure Authority Capacity from such causes customarily insured against and in such amounts as are usually obtained. The Authority shall also use its best efforts to maintain or cause to be maintained any additional or other insurance which the Authority deems necessary or advisable to protect its interests and those of the Senior Bondholders. If any useful portion of the Transmission Project is damaged or destroyed, the Authority shall diligently prosecute 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 Senior Indenture Trustee and applied, to the extent necessary, to the Cost of Acquisition of Capacity. The proceeds of any business interruption loss insurance shall be paid into the Revenue Fund.

Events of Default and Remedies

Events of Default specified in the Senior Indenture include failure to pay principal or Redemption Price of any Senior Bond when due; failure to pay any interest installment on any Senior Bond or the unsatisfied balance of any Sinking Fund Installment thereon when due; and default for 120 days after written notice thereof from the Senior Indenture Trustee or the Holders of not less than 10% in principal amount of Senior Bonds then Outstanding in the observance or performance of any other covenants, agreements or conditions contained in the Senior Indenture or in the Senior Bonds. Upon the happening of any such Event of Default the Senior Indenture Trustee or the Holders of not less than 25% in principal amount of the Senior Bonds then Outstanding may declare the principal of and accrued interest on all Senior Bonds then Outstanding due and payable immediately (subject to a rescission of such declaration upon the curing of such default before the Senior Bonds have matured).

Upon the occurrence of any Event of Default which has not been remedied, the Authority shall, if demanded by the Senior Indenture Trustee, (1) account, as if it were the trustee of an express trust, for all Revenues and other moneys, securities and funds pledged or held under the Senior Indenture, and (2) cause to be paid over to the Senior Indenture Trustee (a) forthwith, all moneys, securities and funds held by the Authority in any Fund under the Senior Indenture and (b) as received, all Revenues. The Senior Indenture Trustee shall apply all moneys, securities, funds and Revenues received during the continuance of an Event of Default in the following order: (1) to payment of the reasonable and proper charges, expenses and liabilities of the Senior Indenture Trustee and Paying Agents; (2) to the payment of Authority Operating Expenses; and (3) to the payment of interest and principal or Redemption Price then due on the Senior Bonds without preference or priority of interest over principal or principal over interest, unless the principal of all Senior Bonds has not been declared due and payable, in which case first to the payment of interest and second to the payment of principal or Redemption Price on those Senior Bonds which have become due and payable in order of their due dates, and if the amount available for such payment shall not be sufficient to pay such amounts in full, then to the payment thereof, ratably, according to the amounts of interest or principal or Redemption Price, respectively, due on such date. In addition, the Senior Indenture Trustee shall have the right to apply in an appropriate proceeding for appointment of a receiver of Authority Capacity.

If an Event of Default has occurred and has not been remedied the Senior Indenture Trustee may, and on request of the Holders of not less than 25% in principal amount of Senior Bonds Outstanding shall, proceed to protect and enforce its rights and the rights of the Senior Bondholders under the Senior Indenture forthwith by a suit or suits in equity or at law, whether for the specific performance of any covenant in the Senior Indenture or in aid of the execution of any power granted in the Senior Indenture or any remedy granted under the Act, or for an accounting against the Authority as if it were the trustee of an express trust, or in the enforcement of any other legal or equitable right, as the Senior Indenture Trustee deems most effectual to enforce any of its rights or to perform any of its duties under the Senior Indenture. The Senior Indenture Trustee may, and upon the request of the Holders of a majority in principal amount of the Senior 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 Senior Indenture or to preserve or protect the interests of the Senior Indenture Trustee and of the Senior Bondholders.

No Senior Bondholder shall have any right to institute any suit, action or proceeding for the enforcement of any provision of the Senior Indenture or the execution of any trust under the Senior
Indenture or for any remedy under the Senior Indenture, unless (1) such Senior Bondholder previously has given the Senior Indenture Trustee written notice of an Event of Default, (2) the Holders of at least 25% in principal amount of the Senior Bonds then Outstanding have filed a written request with the Senior Indenture Trustee and have offered the Senior Indenture Trustee a reasonable opportunity to exercise its powers or to institute such suit, action or proceeding, and (3) there have been offered to the Senior Indenture Trustee adequate security and indemnity against its costs, expenses and liabilities to be incurred and the Senior Indenture Trustee has refused to comply with such request within 60 days after receipt by it of such notice, request and offer of indemnity. The Senior Indenture provides that nothing therein or in the Senior Bonds affects or impairs the Authority’s obligations to pay the principal or Redemption Price, if any, of the Senior Bonds and interest thereon when due or the right of any Senior Bondholder to enforce such payment of his or her Senior Bonds.

The Holders of not less than a majority in principal amount of Senior Bonds then Outstanding may direct the time, method and place of conducting any proceeding for any remedy available to the Senior Indenture Trustee, or exercising any trust or power conferred upon the Senior Indenture Trustee, subject to the Senior Indenture 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 Senior Indenture Trustee in personal liability or would be unjustly prejudicial to Senior Bondholders not parties to such direction.

**SUMMARY OF CERTAIN PROVISIONS OF THE 2015 SERIES C SUBORDINATED INDENTURE**

The following is a summary of certain provisions of the 2015 Series C Subordinated Indenture. This summary is not to be considered a full statement of the terms of the 2015 Series C Subordinated Indenture and accordingly is qualified by reference thereto and is subject to the full text thereof. Capitalized terms not defined in this summary or in the Official Statement have the respective meanings set forth in the 2015 Series C Subordinated Indenture.

**Certain Definitions**

*Available Revenues* shall have the meaning ascribed thereto in the Senior Indenture.

*Bondowner* or *Owner* shall mean each person or entity who is the registered owner of any 2015 Series C Subordinate Bond or Bonds.

*Business Day* shall mean a day (a) other than a Saturday, a Sunday or any other day on which banks located in the city in which the principal office of the Trustee or the Paying Agent is located, are required or authorized by law to close, and (b) on which the New York Stock Exchange is not closed.

*Debt Service* shall mean, with respect to any period, an amount equal to the sum of (i) interest accruing during such period on the Outstanding 2015 Series C Subordinate Bonds, and (ii) that portion of each Principal Installment of the Outstanding 2015 Series C Subordinate Bonds that would become due during such period if such Principal Installment were deemed to become due daily in equal amounts from the next preceding Principal Installment due date for the 2015 Series C Subordinate Bonds (or, if there shall be no such preceding Principal Installment due date, from a date one year preceding the due date of such Principal Installment or the date of initial issuance and delivery of the 2015 Series C Subordinate Bonds, whichever is later). Such interest and Principal Installment for the 2015 Series C Subordinate Bonds shall be calculated on the assumption that no 2015 Series C Subordinate Bonds Outstanding on the date of calculation will cease to be Outstanding except by reason of the payment of each Principal Installment on the due date thereof.
Defeasance Obligations shall mean (i) non-callable, direct obligations of the United States of America, obligations fully and unconditionally guaranteed as to payment of principal and interest by the United States of America including, but not limited to, the interest components of Resolution Funding Corporation securities and obligations of the United States Agency for International Development, as well as non-callable, senior debt obligations of the Federal National Mortgage Association, the Federal Home Loan Mortgage Corporation, the Federal Home Loan Bank System and the Federal Farm Credit System (collectively, “Government Obligations”); or (ii) any bonds or other obligations of any state of the United States of America or of any agency, instrumentality or local governmental unit of any such state which are not callable at the option of the obligor prior to maturity or as to which irrevocable instructions have been given by the obligor to call on the date specified in the notice and (a) rated no lower than the then-current rating on direct obligations of, or obligations the principal of and interest on which are unconditionally guaranteed by, the United States of America (or by an agency thereof to the extent such obligations are backed by the full faith and credit of the United States of America), or (b)(1) which are fully secured as to principal and interest and redemption premium, if any, by a fund consisting only of cash and/or Government Obligations, which fund may be applied only to the payment of such principal of and interest and redemption premium, if any, on such bonds or other obligations on the maturity date or dates thereof or the specified redemption date or dates pursuant to such irrevocable instructions, as appropriate, and (2) which fund is sufficient, as verified by a nationally recognized independent certified public accountant or independent arbitrage consultant, to pay principal of and interest and redemption premium, if any, on the bonds or other obligations described in this clause (ii) on the maturity date or dates thereof or on the redemption date or dates specified in the irrevocable instructions referred to above, as appropriate.

Issue Date shall mean the date of original issuance of the 2015 Series C Subordinate Bonds.

Opinion of Bond Counsel shall mean an opinion signed by Bond Counsel.

Outstanding, when used with reference to 2015 Series C Subordinate Bonds, shall mean, as of any date, 2015 Series C Subordinate Bonds theretofore or thereupon being authenticated and delivered under the 2015 Series C Subordinated Indenture except:

(i) 2015 Series C Subordinate Bonds cancelled by the Trustee on or prior to such date;

(ii) if applicable, 2015 Series C Subordinate Bonds (or portions thereof) for the payment or redemption of which moneys, equal to the principal amount or Redemption Price thereof, as the case may be, with interest, if any, to the date of maturity or redemption date, shall be held in trust under the 2015 Series C Subordinated Indenture and set aside for such payment or redemption (whether at or prior to the maturity or redemption date), provided that if such 2015 Series C Subordinate Bonds (or portions thereof) are to be redeemed, notice of such redemption shall have been given as provided in the 2015 Series C Subordinated Indenture or provision satisfactory to the Trustee shall have been made for the giving of such notice;

(iii) 2015 Series C Subordinate Bonds in lieu of or in substitution for which other 2015 Series C Subordinate Bonds shall have been authenticated and delivered pursuant to the 2015 Series C Subordinated Indenture; and

(iv) 2015 Series C Subordinate Bonds deemed to have been paid as provided in the 2015 Series C Subordinated Indenture.

Parity Swap shall mean any interest rate exchange or swap agreement, cash flow exchange or swap agreement or other similar financial agreement (including all confirmations, schedules, exhibits,
attachments, appendices and other documentation attached to such agreement or forming a part thereof or incorporated therein) (a) that is entered into by the Authority and a Parity Swap Provider (and, if applicable, the Trustee), (b) that is permitted to be entered into by the Authority under the laws of the State of California applicable thereto at the time the Authority enters into such agreement, as evidenced by an opinion of counsel acceptable to the Authority, (c) as to which the documentation thereof provides that payments to be made by the Authority pursuant to such agreement (other than termination payments thereunder, which shall be payable on a basis subordinate and junior to the payments to be made on the 2015 Series C Subordinate Bonds and any other payments due on the Parity Swap) constitute obligations payable on a parity basis with the payments to be made on the 2015 Series C Subordinate Bonds as and to the extent provided in the 2015 Series C Subordinated Indenture and (d) designated in writing to the Trustee by an Authorized Authority Representative as a Parity Swap under the 2015 Series C Subordinated Indenture.

Parity Swap Provider shall mean, with respect to each Parity Swap, the entity (other than the Authority and, if applicable, the Trustee) that is a party thereto, and its permitted successors and assigns, whose public credit ratings, or whose obligations under a Parity Swap are guaranteed by a financial institution whose public credit ratings, are (at the time the applicable Parity Swap is entered into), unless otherwise approved by the Authority in not lower than the second highest rating category (without regard to gradations within such category by any two nationally-recognized credit rating agencies.

Pledged Revenues shall mean all Available Revenues transferred to and deposited in the 2015 Series C Pledged Revenues Account pursuant to the Senior Indenture (including the Twenty-Eighth Supplemental Indenture).

Principal Installment shall mean, as of any date of calculation, so long as any 2015 Series C Subordinate Bond is Outstanding, (i) the principal amount of the 2015 Series C Subordinate Bonds due on a certain future date for which no Sinking Fund Installments have been established, or (ii) if applicable, the unsatisfied balance of any Sinking Fund Installments due on a certain future date for the 2015 Series C Subordinate Bonds, plus the amount of the sinking fund redemption premiums, if any, that would be payable upon redemption of such 2015 Series C Subordinate Bonds on such future date in a principal amount equal to said unsatisfied balance of such Sinking Fund Installments, or (iii) if such future dates coincide as to different 2015 Series C Subordinate Bonds, the sum of such principal amount of 2015 Series C Subordinate Bonds and of such unsatisfied balance of Sinking Fund Installments due on such future date plus such applicable redemption premiums, if any.

Reserve Account Policy shall mean any surety bond, insurance policy, line of credit, letter of credit or similar instrument issued to the Trustee by a company licensed to issue a surety bond, insurance policy, line of credit, letter of credit or similar instrument guaranteeing the timely payment of debt service on the Bonds to which it relates (a “municipal bond insurer”), which municipal bond insurer, at the time any such surety bond, insurance policy, line of credit, letter of credit or similar instrument is issued, shall have its claims paying ability rated in not lower than the second highest rating category (without regard to any gradations within any such category) by at least two nationally-recognized credit rating agencies.

Reserve Requirement shall mean an amount equal to $0.00.

Securities Depository shall mean The Depository Trust Company and its successors and assigns or if (i) the then Securities Depository resigns from its functions as depository of the 2015 Series C Subordinate Bonds or (ii) the Authority discontinues use of the then Securities Depository pursuant to the 2015 Series C Subordinated Indenture, any other securities depository which agrees to follow the procedures required to be followed by a securities depository in connection with the 2015 Series C Subordinate Bonds and which is selected by the Authority.
Twenty-Eighth Supplemental Indenture shall mean the Twenty-Eighth Supplemental Indenture, dated as of March 1, 2015, as supplemented or amended from time to time, from the Authority to U.S. Bank National Association, as trustee, amending and supplementing the Senior Indenture as theretofore in effect.

2015 Series C Accrued Debt Service shall mean, as of any date of calculation, an amount equal to the amount of accrued Debt Service, calculating the accrued Debt Service as an amount equal to the sum of (i) interest on the 2015C Subordinate Bonds accrued and unpaid and to accrue to the end of the then current calendar month, and (ii) Principal Installments on the 2015 Series C Subordinate Bonds due and unpaid and that portion of the Principal Installment on the 2015 Series C Subordinate Bonds that is to become due (if deemed to accrue in the manner set forth in the definition of Debt Service) by the end of such calendar month. For purposes of this definition, interest shall accrue with respect to each month of any Fiscal Year based on the total amount of interest payable on the January 1 included in such Fiscal Year and the next succeeding July 1, divided by twelve (12).

2015 Series C Subordinate Bonds shall mean the Authority’s Transmission Project Revenue Bonds, 2015 Subordinate Refunding Series C, authenticated and delivered under and pursuant to the 2015 Series C Subordinated Indenture.

2015 Series C Subordinated Indenture shall mean the Indenture of Trust relating to the 2015 Series C Subordinate Bonds, dated as of March 1, 2015, from the Authority to U.S. Bank National Association, as trustee, as supplemented and amended from time to time.

Pledge Effected by the 2015 Series C Subordinated Indenture

Under the 2015 Series C Subordinated Indenture, the Authority has pledged and assigned to the Trustee, for the benefit of the owners of the 2015 Series C Subordinate Bonds and any Parity Swap Providers, (1) the Pledged Revenues and (2) the 2015 Series C Issue Fund and all Accounts established therein by the 2015 Series C Subordinated Indenture; subject only to the provisions of the 2015 Series C Subordinated Indenture and the Twenty-Eighth Supplemental Indenture permitting the application thereof for the purposes and on the terms and conditions set forth in the 2015 Series C Subordinated Indenture and the Twenty-Eighth Supplemental Indenture, respectively, as security for (i) the payment of the 2015 Series C Subordinate Bonds, the interest thereon and premium, if any, with respect thereto, (ii) as security for the payment obligations of the Authority under any Parity Swaps and (iii) as security for the performance of any other obligations of the Authority under the 2015 Series C Subordinated Indenture, all in accordance with the provisions of the 2015 Series C Subordinate Bonds, the 2015 Series C Subordinated Indenture, the Twenty-Eighth Supplemental Indenture and any Parity Swaps. The 2015 Series C Subordinate Bonds shall be special, limited obligations of the Authority payable solely from and secured as to the payment of the principal or Redemption Price thereof, and interest thereon, in accordance with their terms and the provisions of the 2015 Series C Subordinated Indenture and the Twenty-Eighth Supplemental Indenture solely by the moneys, Fund and Accounts set forth in the 2015 Series C Subordinated Indenture. The pledge made in the 2015 Series C Subordinated Indenture with respect to the 2015 Series C Subordinate Bonds and any Parity Swaps is valid and binding upon delivery of the 2015 Series C Subordinate Bonds, and the Pledged Revenues and the 2015 Series C Issue Fund shall immediately be subject to the lien of such pledge without any physical delivery thereof or any further act, and the applicable lien of such pledge shall be valid and binding as against all parties having claims of any kind in tort, contract or otherwise against the Authority irrespective of whether such parties have notice thereof. The 2015 Series C Subordinate Bonds and any Parity Swaps shall not be deemed to be Bonds as defined in the Senior Indenture.
Nature of Obligation

The 2015 Series C Subordinate Bonds are not an obligation of the State of California or any public agency thereof, other than the Authority, or any member of the Authority or any Project Participant and neither the faith and credit nor the taxing power of the State of California or any public agency thereof nor any member of the Authority nor any Project Participant is pledged for the payment of the principal or Redemption Price of, or interest on, the 2015 Series C Subordinate Bonds or the obligations of the Authority (or the Trustee, if applicable) under any Parity Swaps. The 2015 Series C Subordinate Bonds and any Parity Swaps shall never constitute the debt or indebtedness of the Authority within the meaning of any provision or limitation of the Constitution of the State of California or statutes of the State of California, nor shall they constitute or give rise to a pecuniary liability of the Authority or a charge against its general credit.

Application of Pledged Revenues

Pledged Revenues deposited in the 2015 Series C Subordinated Indenture are pledged by the 2015 Series C Subordinated Indenture to payment of the principal and Redemption Price of, and interest on, the 2015 Series C Subordinate Bonds and for payment of the obligations of the Authority (or the Trustee, if applicable) under any Parity Swaps. The 2015 Series C Subordinated Indenture establishes the 2015 Series C Issue Fund and the following Accounts therein, to be held by the Trustee for the application of Pledged Revenues:

- 2015 Series C Pledged Revenues Account
- 2015 Series C Payment Account
- 2015 Series C Reserve Account
- 2015 Series C Charges Account
- 2015 Series C Remainder Account
- 2015 Series C Costs of Issuance Account

Amounts deposited in the 2015 Series C Costs of Issuance Account shall be expended from time to time to pay Costs of Issuance relating to the 2015 Series C Subordinate Bonds upon receipt by the Trustee of a requisition or other written directions signed by an Authorized Authority Representative. If any amount shall remain in the 2015 Series C Costs of Issuance Account when all Costs of Issuance have been paid, as stated in a certificate of an Authorized Authority Representative, such amount shall be transferred to the 2015 Series C Remainder Account or if no such certificate is received, then 180 days after the Issue Date of the 2015 Series C Subordinate Bonds the Trustee shall make such transfer.

The Trustee may, with the prior written consent of the Authority, establish additional accounts or subaccounts within the 2015 Series C Issue Fund or any of the Accounts therein, respectively, if the Trustee determines that such additional accounts or subaccounts would be advantageous or desirable.

All Pledged Revenues are to be deposited promptly in the 2015 Series C Pledged Revenues Account upon receipt thereof. Amounts in the 2015 Series C Pledged Revenues Account are to be paid as soon as practicable in each month after their deposit, but in any case, no later than 12:00 noon, New York City time, on the last Business Day of the month, in the following order of priority for application therefrom as follows:

1. To the 2015 Series C Payment Account, the amount, if any, required so that the balance in said Account shall equal the sum of (A) the 2015 Series C Accrued Debt Service as of the last day of the then current month, and (B) all amounts due and payable by the Authority
under any Parity Swaps during such month (or the entire amount transferred by the Trustee from the 2015 Series C Pledged Revenues Account if less than the required amount).

The Trustee shall pay out of the 2015 Series C Payment Account, subject to the two immediately following paragraphs, without preference or priority of one transfer over the others (i) to the Paying Agent (a) on or before each Interest Payment Date the amount required for the interest payable on the 2015 Series C Subordinate Bonds on such date, (b) on or before each Principal Installment due date, the amount required for the Principal Installment payable on such due date, and (c) on or before any redemption date for the 2015 Series C Subordinate Bonds, the amount required for the payment of principal, premium, if any, and interest on the 2015 Series C Subordinate Bonds then to be redeemed; and (ii) to any Parity Swap Providers, any amounts due and payable by the Authority under the Parity Swaps during such month. Amounts so paid to the Paying Agent with respect to the 2015 Series C Subordinate Bonds shall be applied by the Paying Agent on and after the due dates thereof. The Authority shall inform the Trustee, or cause the Trustee to be informed, in writing of amounts payable from the 2015 Series C Payment Account pursuant to clause (ii). Notwithstanding anything to the contrary in the 2015 Series C Subordinated Indenture, payments due to any Parity Swap Providers during a given month shall not be paid earlier in such month than the payment of any interest or Principal Installment due during such month.

All amounts held at any time in the 2015 Series C Payment Account shall be held until applied on parity basis for the ratable security and payment of (i) 2015 Series C Accrued Debt Service and (ii) amounts due and payable by the Authority under any Parity Swaps, at any time in proportion to the amounts accrued or due and payable, as applicable.

In the event of the refunding of all or a portion of the 2015 Series C Subordinate Bonds, the Trustee shall, upon the direction of the Authority with the advice of Bond Counsel, withdraw from the 2015 Series C Payment Account amounts accumulated therein with respect to Debt Service on the 2015 Series C Subordinate Bonds being refunded and, except as otherwise directed by the Authority, deposit such amounts with itself as Trustee to be held for the payment of the principal or Redemption Price, if applicable, of and interest on the maturity or maturities of the 2015 Series C Subordinate Bonds being refunded; provided that such withdrawal shall not be made unless: (i) immediately thereafter the maturity or maturities of 2015 Series C Subordinate Bonds being refunded shall be deemed to have been paid pursuant to the 2015 Series C Subordinated Indenture; and (ii) the amount, if any, remaining in the 2015 Series C Payment Account after such withdrawal shall not be less than the requirement of such Account pursuant to the 2015 Series C Subordinated Indenture.

2. To the 2015 Series C Reserve Account, upon the occurrence of any deficiency therein (if applicable), (a) if the 2015 Series C Reserve Account is at that time funded by a Reserve Account Policy the provider of which has not failed to make payments thereunder, the amount of each unrepaid prior withdrawal from the 2015 Series C Reserve Account so that the provider of the Reserve Account Policy has been repaid for any draw made under such Policy for such Account or (b) if the 2015 Series C Reserve Account is not at that time funded by a Reserve Account Policy or, if funded by a Reserve Account Policy, the provider of such Reserve Account Policy has failed to make payment thereunder, the amount, if any, required for such Account to equal the Reserve Requirement as of the last day of the then current month (or the entire amount so transferred by the Trustee from the 2015 Series C Pledged Revenues Account after making the deposit in numbered paragraph 1 above if less than the required amount).

Pursuant to the 2015 Series C Subordinated Indenture, the Reserve Requirement for the
2015 Series C Subordinate Bonds shall be equal to $0.00, and the 2015 Series C Reserve Account will not be funded.

If at any time the amount in the 2015 Series C Payment Account shall be less than the amount required to be in such Account (if any), the Trustee shall transfer amounts (if any) from the 2015 Series C Reserve Account to the 2015 Series C Payment Account (or, if applicable, the Trustee shall draw on the Reserve Account Policy (if any) and deposit the proceeds thereof in the 2015 Series C Payment Account) to the extent necessary to make good the deficiency.

Whenever the moneys on deposit in the 2015 Series C Reserve Account shall exceed the Reserve Requirement for the 2015 Series C Subordinate Bonds, if any, such excess (to the extent not required to be transferred to the trustee for the Senior Bonds) shall be transferred to the 2015 Series C Pledged Revenues Account.

In the event of the refunding of all or any portion of the 2015 Series C Subordinate Bonds, the Trustee shall, upon the direction of the Authority with the advice of Bond Counsel, transfer from the 2015 Series C Reserve Account any amounts accumulated therein, except as otherwise directed by the Authority, deposit such amounts with itself as Trustee to be held for the payment of the principal or Redemption Price, if applicable, and interest on the maturity or maturities of the 2015 Series C Subordinate Bonds being refunded; provided that such withdrawal shall not be made unless (a) immediately thereafter the maturity or maturities of the 2015 Series C Subordinate Bonds being refunded shall be deemed to have been paid pursuant to the 2015 Series C Subordinated Indenture, and (b) the amount remaining in the 2015 Series C Reserve Account after such withdrawal shall not be less than the requirement of such Account, if any, pursuant to the 2015 Series C Subordinated Indenture.

If a Reserve Account Policy shall be in full force and effect, any deposits required to be made with respect to the 2015 Series C Reserve Account pursuant to the 2015 Series C Subordinated Indenture shall include any amounts due to the provider of such Reserve Account Policy resulting from a draw on such Reserve Account Policy (which amounts shall constitute a “deficiency” or “withdrawal” from the 2015 Series C Reserve Account as provided in the 2015 Series C Subordinated Indenture. Any such amounts shall be paid to the provider of any Reserve Account Policy as provided in such Reserve Account Policy or any related agreement.

3. To the 2015 Series C Charges Account, the amount, if any, required so that the balance in said Account equals the sum of all amounts accrued or due and payable by the Authority as charges and fees to the Trustee or the Paying Agent during such month (or the entire amount transferred by the Trustee from the 2015 Series C Pledged Revenues Account after making the deposits in numbered paragraphs 1 and 2 above if less than the required amount).

The Trustee shall transfer moneys from the 2015 Series C Charges Account in the following amounts and in the following order of priority: (a) to the 2015 Series C Payment Account and the 2015 Series C Reserve Account the amount necessary (or all the moneys in the 2015 Series C Charges Account if less than the amount necessary) to make up any deficiencies in payments to the 2015 Series C Payment Account and the 2015 Series C Reserve Account required by numbered paragraphs 1 and 2 above, and (b) in the event of any transfer of moneys from the 2015 Series C Reserve Account to the 2015 Series C Payment Account, to the 2015 Series C Reserve Account the amount of the deficiency in such Account resulting from such transfer.
The Authority shall inform the Trustee, or cause the Trustee to be informed, in writing of amounts payable from the 2015 Series C Charges Account and the Trustee shall pay out of the 2015 Series C Charges Account to the Trustee and the Paying Agent, the amounts due and payable by the Authority as fees and charges to each of them for their charges and costs during such month.

4. To the 2015 Series C Remainder Account, the remaining balance, if any, in the 2015 Series C Pledged Revenues Account after making the deposits pursuant to numbered paragraphs 1, 2 and 3 above.

The Trustee shall transfer from the 2015 Series C Remainder Account the following amounts in the following order of priority: (i) to the 2015 Series C Payment Account and the 2015 Series C Reserve Account the amount necessary (or all the moneys in the 2015 Series C Remainder Account if less than the amount necessary) to make up any deficiencies in payments to said 2015 Series C Payment Account and 2015 Series C Reserve Account required by numbered paragraphs 1 and 2 above; (ii) in the event of any transfer of moneys from the 2015 Series C Reserve Account to the 2015 Series C Payment Account, to the 2015 Series C Reserve Account the amount of the deficiency in such Account resulting from such transfer, if any; and (iii) to the 2015 Series C Charges Account the amount necessary (or all the moneys in the 2015 Series C Remainder Account if less than the amount necessary) to make up any deficiencies in payments to said 2015 Series C Charges Account required by numbered paragraph 3 above.

Amounts in the 2015 Series C Remainder Account not required to meet a deficiency described in the preceding paragraph and not required to be transferred to the trustee for the Senior Bonds pursuant to the 2015 Series C Subordinated Indenture will, upon determination of the Authority evidenced by a certificate of an Authorized Authority Representative delivered to the Trustee and after consultation with Bond Counsel, be applied to or set aside for any lawful purpose of the Authority related to the Transmission Project or the Authority Capacity.

**Investment of Certain Accounts**

The 2015 Series C Subordinated Indenture provides that moneys held in the 2015 Series C Issue Fund or any Account therein shall be invested and reinvested by the Trustee to the fullest extent practicable in Investment Securities. The 2015 Series C Subordinated Indenture provides that amounts in the 2015 Series C Remainder Account shall be invested or reinvested in Investment Securities that mature or are available within five years from the date of such investment, and, in any case, the Investment Securities in the 2015 Series C Issue Fund and Accounts therein shall mature or be available no later than such times as are necessary to provide moneys when needed for payments from such Accounts.

Interest and other investment income (net of that which (i) represents a return of accrued interest paid in connection with the purchase of any investment and (ii) is required to offset the amortization of any premium paid in connection with the purchase of any investment) earned on any moneys or investments in the 2015 Series C Issue Fund and the Accounts established therein, shall, to the extent amounts in such Fund or Account exceed the requirements for deposit therein and to the extent required by the Senior Indenture, be transferred to the trustee for the Senior Bonds for deposit in the Revenue Fund and to the extent not required to be transferred to the trustee for the Senior Bonds, be transferred to the 2015 Series C Pledged Revenues Account or as otherwise instructed by an Authorized Authority Representative.

In computing the amount in the 2015 Series C Issue Fund or any Account created under the 2015 Series C Subordinated Indenture, obligations purchased as an investment of moneys therein shall be
valued at the greater of the cost of such obligations or the amortized value thereof, whichever is lower, exclusive of accrued interest. Such computations shall be determined as of July 1 in each year.

**Creation of Liens; Sale of Authority Capacity**

The Authority shall not issue any bonds, notes, debentures or other evidences of indebtedness of similar nature, other than the 2015 Series C Subordinate Bonds or Parity Swaps, payable out of or secured by a security interest in or a pledge or assignment of the Pledged Revenues or other moneys, securities or funds held or set aside by the Authority or by the Fiduciaries under the 2015 Series C Subordinated Indenture for the benefit of the Owners of the 2015 Series C Subordinate Bonds and for any Parity Swap Providers and shall not create or cause to be created any other lien or charge thereon; provided, however, that nothing in the 2015 Series C Subordinated Indenture shall preclude the issuance of any bonds, notes, debentures, evidences of indebtedness or the incurrence of any obligation (including, but not limited to, any interest rate exchange or swap agreement, cash flow exchange or swap agreement or other similar financial agreement) if same is payable on a basis subordinate and junior to the 2015 Series C Subordinate Bonds and the Parity Swaps, if any, and secured by a lien or charge on Pledged Revenues that is subordinate and junior to the lien on the 2015 Series C Subordinate Bonds and any such Parity Swaps on Pledged Revenues.

The Authority will not sell, assign or otherwise dispose of Authority Capacity or any portion thereof except as provided in the Senior Indenture. The Authority will not sell any transmission service utilizing Authority Capacity except as provided in the Transmission Service Contracts or as allowed by applicable tax laws and regulations.

**Rate Covenant**

The Authority covenants in the 2015 Series C Subordinated Indenture that, as long as any 2015 Series C Subordinate Bonds are Outstanding, it has and will have good right and lawful power to establish charges and cause to be collected amounts with respect to the use of Authority Capacity, subject to the terms of the Transmission Service Contracts.

The Authority covenants in the 2015 Series C Subordinated Indenture that it shall at all times establish charges and cause to be collected amounts for the use of Authority Capacity (including amounts payable under the Transmission Service Contracts) as shall be required to provide Revenues at least sufficient in each Fiscal Year, together with other available funds, for the payment (without duplication) of all amounts required to be paid from Revenues or Available Revenues during such Fiscal Year pursuant to the Senior Indenture, including, but not limited to, all amounts required to be paid from Available Revenues transferred to the Pledged Revenues Accounts during such Fiscal Year pursuant to the Prior Subordinated Indentures, and from the Pledged Revenues during such Fiscal Year pursuant to the 2015 Series C Subordinated Indenture.

The Authority will not furnish or supply or cause to be furnished or supplied any use or service of Authority Capacity free of charge to any person, firm or corporation, public or private, and the Authority will, subject to the 2015 Series C Subordinated Indenture and consistent with the Transmission Project Agreements, enforce the payment of any and all amounts owing to the Authority by reason of Authority Capacity by discontinuing such use or service, or by filing suit therefor, as soon as practicable after any such amounts are due, or by both such discontinuance and by filing suit.
Covenant With Respect to Transmission Service Contracts

Subject to the 2015 Series C Subordinated Indenture, the Authority shall enforce or cause to be enforced the provisions of the Transmission Service Contracts and duly perform its covenants and agreements thereunder. The Authority 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 Transmission Service Contracts that will impermissibly reduce the payments required thereunder or which will in any manner materially impair or materially adversely affect the rights of the Authority thereunder or the rights or security of Owners under the 2015 Series C Subordinated Indenture; provided that the Authority is not prohibited from amending any Transmission Service Contract to the extent expressly permitted therein. Except as expressly authorized in the Senior Indenture, the Authority will not consent or agree to or permit any rescission or any amendment to or otherwise take any action under or in connection with the Senior Indenture which will in any manner materially impair or materially adversely affect the rights of the Authority thereunder or the rights or security of the Owners under the 2015 Series C Subordinated Indenture.

Annual Budget

The Authority shall adopt and file not less than 30 but no more than 45 days prior to the beginning of each Fiscal Year with the Trustee for each Fiscal Year an Annual Budget prepared in accordance with, and in the manner contemplated by, the Transmission Service Contracts and the Senior Indenture. The Annual Budget shall include monthly appropriations for the estimated amount to be deposited in each month of such Fiscal Year in the 2015 Series C Issue Fund, including particularly the amounts required for the accrual or payment (as applicable) of 2015 Series C Accrued Debt Service and the obligations of the Authority (or the Trustee, if applicable) under any Parity Swaps, so that the 2015 Series C Payment Account, the 2015 Series C Charges Account, and the 2015 Series C Reserve Account (if funded) shall be maintained at the respective balances required by the 2015 Series C Subordinated Indenture and the provider of any Reserve Account Policy shall be repaid for any draw made under such Reserve Account Policy for the 2015 Series C Reserve Account.

The Authority shall review quarterly its estimates set forth in the Annual Budget for such Fiscal Year, and in the event such estimates do not substantially correspond with the actual revenues, expenses or other requirements, the Authority shall adopt in accordance with the provisions of the Transmission Service Contracts and file with the Trustee an amended Annual Budget for the remainder of such Fiscal Year. The Authority may also adopt in accordance with the provisions of the Transmission Service Contracts and file with the Trustee an amended Annual Budget for the remainder of such Fiscal Year, if, at any time during such Fiscal Year, extraordinary receipts or payments of unusual costs relating to Authority Capacity, or the amounts in the 2015 Series C Payment Account, the 2015 Series C Reserve Account and the 2015 Series C Charges Account are less than the respective balances required under the 2015 Series C Subordinated Indenture. The Authority may also adopt, at any time in accordance with the provisions of the Transmission Service Contracts and file with the Trustee an amended Annual Budget for the remainder of the then current Fiscal Year.

Accounts and Reports

The Authority shall keep or cause to be kept books of record and account (separate from all other records and accounts) in which complete and correct entries in all material respects shall be made of its transactions relating to the 2015 Series C Issue Fund and each Account established under the 2015 Series C Subordinated Indenture. Such books, together with the Transmission Service Contracts and all other books and papers of the Authority, including insurance policies maintained by the Authority, relating to Authority Capacity, shall at all times be subject to the inspection of the Trustee (who shall
have no duty to so inspect) and the Owners of an aggregate of not less than five percent (5%) in principal amount of 2015 Series C Subordinate Bonds then Outstanding or their representatives duly authorized in writing.

The Authority shall cause to be filed, annually within 150 days after the close of each Fiscal Year, with the Trustee an annual report for each Fiscal Year, accompanied by an Accountant’s Certificate, relating to Authority Capacity and so long as not contrary to the then current recommendations of the American Institute of Certified Public Accountants, including the statements required by the Senior Indenture. So long as not contrary to the then current recommendations of the American Institute of Certified Public Accountants, such Accountant’s Certificate shall state whether or not, to the knowledge of the signer, the Authority is in default with respect to any of the covenants, agreements or conditions on its part contained in the 2015 Series C Subordinated Indenture, and if so, the nature of such default. The Trustee shall not be responsible to review the financial information contained in such annual report.

The Authority shall file with the Trustee (a) forthwith upon becoming aware of any Event of Default or default in the performance by the Authority of any covenant, agreement or condition contained in the 2015 Series C Subordinated Indenture, a certificate of an Authorized Authority Representative specifying such Event of Default or default and (b) within 150 days after the end of each Fiscal Year, commencing with the first Fiscal Year ending after the issuance of the 2015 Series C Subordinate Bonds, a certificate of an Authorized Authority Representative stating whether, to the best of the signer’s knowledge and belief, the Authority has kept, observed, performed and fulfilled its covenants and obligations contained in the 2015 Series C Subordinated Indenture and whether there exists at the date of such certificate any default by the Authority under the 2015 Series C Subordinated Indenture or any Event of Default or other event that would become an Event of Default upon the lapse of time or giving of notice and if any such default or Event of Default so exists, 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 2015 Series C Subordinated Indenture shall be available for inspection by Owners at the office of the Trustee during business hours and with reasonable prior notice and shall be mailed to each Owner who files a written request therefor with the Trustee. The Trustee may charge each Owner requesting such reports, statements and other documents a reasonable fee to cover reproduction, handling and postage.

**Extension of Payment of 2015 Series C Subordinate Bonds**

The Authority covenants in the 2015 Series C Subordinated Indenture that it shall not directly or indirectly extend or assent to the extension of the maturity of any of the 2015 Series C Subordinate Bonds or the time of payment of any claims for interest by the purchase or funding of such 2015 Series C Subordinate Bonds or claims for interest or by any other arrangement. If the maturity of any of the 2015 Series C Subordinate Bonds or the time for payment of such claims for interest is extended, such 2015 Series C Subordinate Bonds or claims for interest shall not be entitled, in the case of any default under the 2015 Series C Subordinated Indenture, to the benefit of the 2015 Series C Subordinated Indenture or any payment out of the Pledged Revenues or the 2015 Series C Issue Fund, including the investments, if any, thereof, pledged under the 2015 Series C Subordinated Indenture or the moneys (except moneys held in trust for the payment of particular 2015 Series C Subordinate Bonds or claims for interest pursuant to the 2015 Series C Subordinated Indenture) held by the Fiduciaries, except subject to the prior payment of the principal of all 2015 Series C Subordinate Bonds Outstanding the maturity of which has not been extended and of the portion of accrued interest on the 2015 Series C Subordinate Bonds which is not represented by such extended claims for interest. Nothing in the 2015 Series C Subordinated Indenture shall be deemed to limit the right of the Authority to issue refunding bonds or other evidence of
indebtedness to refund the 2015 Series C Subordinate Bonds and such issuance shall not be deemed to constitute an extension of maturity of the 2015 Series C Subordinate Bonds.

Application of Available Revenues; Priority of Payment

The Authority shall set aside or cause to be set aside in the General Reserve Fund under the Senior Indenture in each month Available Revenues in amounts at least sufficient to meet (1) the requirements for such month determined pursuant to the 2015 Series C Subordinated Indenture and (2) all other payments or transfers of Available Revenues required to be made in such month, including all payments or transfers of Available Revenues required to be made in such month pursuant to the Prior Subordinated Indentures. Moneys set aside or transferred to meet the requirements of the Prior Subordinated Indentures shall be applied in a manner such that none shall have priority over or otherwise rank prior to the others. On or before the last Business Day of each month the Authority shall apply or cause to be applied Available Revenues by transfer thereof from said General Reserve Fund (consistent with the 2015 Series C Subordinated Indenture), to the 2015 Series C Pledged Revenues Account in the amount required to meet the requirements for such month determined pursuant to the 2015 Series C Subordinated Indenture.

The Authority shall not authorize or permit any Available Revenues to be set aside, transferred or applied for any purpose pursuant to such terms and provisions or in any manner such that the setting aside, transfer or application shall have priority over or otherwise rank prior to the requirements described above for the setting aside, transferring and application of Available Revenues to meet the requirements determined pursuant to the 2015 Series C Subordinated Indenture.

Amendments and Supplemental Indentures

Except as otherwise provided in the 2015 Series C Subordinated Indenture, any of the provisions of the 2015 Series C Subordinated Indenture may be amended by the Authority by a Supplemental Indenture upon the written consent of the Owners of at least a majority in aggregate principal amount of 2015 Series C Subordinate Bonds then Outstanding and, if less than all of the Outstanding 2015 Series C Subordinate Bonds are affected by the amendment, the Owners of at least a majority in aggregate principal amount of Outstanding 2015 Series C Subordinate Bonds so affected. Moreover, if such amendment or modification will not take effect so long as any 2015 Series C Subordinate Bonds of any specified like maturity remain Outstanding, the consent of the Owners of such 2015 Series C Subordinate Bonds will not be required, and such 2015 Series C Subordinate Bonds shall not be deemed to be Outstanding for the purposes of such calculation. No such amendment or modification may permit a change in the terms of redemption or maturity of the principal of any Outstanding 2015 Series C Subordinate Bonds or of any installment of interest thereon or make any reduction in the principal amount, Redemption Price (if applicable), or interest rate thereon without the consent of the Owner of such 2015 Series C Subordinate Bond, or reduce the percentages of the consents of the Owners of which are required to effect such amendment or modification, or shall change or modify any of the rights or obligations of any Fiduciary without its written assent thereto.

The Authority may adopt Supplemental Indentures of Trust without the consent of the Owners for any of the following purposes: (1) to add to the covenants and agreements of the Authority contained in the 2015 Series C Subordinated Indenture, other covenants and agreements to be observed by the Authority that are not contrary to or inconsistent with the 2015 Series C Subordinated Indenture then in effect; (2) to add to the limitations and restrictions contained in the 2015 Series C Subordinated Indenture, other limitations and restrictions to be observed by the Authority that are not contrary to or inconsistent with the 2015 Series C Subordinated Indenture then in effect; (3) to confirm any security interest or pledge created under the 2015 Series C Subordinated Indenture; (4) to modify, amend or supplement the
2015 Series C Subordinated Indenture in such manner as to permit the qualification thereof under the Trust Indenture Act of 1939, as amended, or any similar federal statute hereafter in effect, and to add such other terms, conditions and provisions as may be permitted by said act or similar federal statute, and which shall not materially and adversely affect the interests of the Owners of any of the 2015 Series C Subordinate Bonds; (5) to modify any of the provisions of the 2015 Series C Subordinated Indenture in any other respect if (i) no 2015 Series C Subordinate Bonds are Outstanding at the date of execution of such Supplemental Indenture of Trust or (ii) (a) such modification shall be, and be expressed to be, effective only after all 2015 Series C Subordinate Bonds then Outstanding at the date of the execution and delivery of such Supplemental Indenture of Trust shall cease to be Outstanding and (b) such Supplemental Indenture of Trust shall be specifically referred to in the text of all 2015 Series C Subordinate Bonds authenticated and delivered after the date of execution and delivery of such Supplemental Indenture of Trust and of 2015 Series C Subordinate Bonds issued in exchange therefor or in place thereof; (6) to amend, modify, or supplement the 2015 Series C Subordinated Indenture in such manner as does not materially adversely affect the rights of the Owners of the 2015 Series C Subordinate Bonds (including, but not limited to, amending, modifying or supplementing the 2015 Series C Subordinated Indenture in such manner as the Authority deems appropriate to provide for an interest rate exchange or swap agreement, cash flow exchange or swap agreement or other similar financial agreement payable on a basis subordinate and junior to the 2015 Series C Subordinate Bonds and any Parity Swaps, as provided in the 2015 Series C Subordinated Indenture), provided that the Trustee is first furnished with an Opinion of Bond Counsel to the effect that such amendment, modification or supplement is permitted under the 2015 Series C Subordinated Indenture and shall not adversely affect the validity of the 2015 Series C Subordinate Bonds or the exclusion of interest on the 2015 Series C Subordinate Bonds from gross income of the Owners for federal income tax purposes; and (7) to comply with additional requirements that a Rating Agency may impose in order to issue or maintain a rating on the 2015 Series C Subordinate Bonds, provided that any Supplemental Indenture the purpose of which is to effect such changes shall be effective only upon delivery to the Authority and the Trustee of an Opinion of Bond Counsel that such changes shall not adversely affect the validity of the 2015 Series C Subordinate Bonds or the exclusion of interest on the 2015 Series C Subordinate Bonds from the gross income of the Owners thereof for federal income tax purposes.

The Authority may adopt Supplemental Indentures of Trust with the consent of the Trustee (without the consent of any Owners of the 2015 Series C Subordinate Bonds) to cure any ambiguity, supply any omission, or cure or correct any defect or inconsistent provision in the 2015 Series C Subordinated Indenture or to insert such provisions clarifying matters or questions arising under the 2015 Series C Subordinated Indenture as are necessary or desirable and not contrary to or inconsistent with the 2015 Series C Subordinated Indenture.

**Fiduciaries**

The Trustee may at any time resign by giving not less than 60 days’ written notice to the Authority and any Parity Swap Providers specifying the date when such resignation shall take effect, and such resignation shall take effect upon the day specified in such notice unless previously a successor shall have been appointed by the Authority with the approval of the Owners as provided in the 2015 Series C Subordinated Indenture, in which event such resignation shall take effect immediately on the appointment of such successor. The Trustee may at any time be removed by (i) an instrument in writing, filed with the Trustee, signed by two Authorized Authority Representatives, unless an Event of Default has occurred and is continuing, or (ii) an instrument or concurrent instruments in writing, filed with the Trustee, and signed by the Owners of a majority in principal amount of the 2015 Series C Subordinate Bonds then Outstanding or their attorneys-in-fact duly authorized. Such removal shall take effect immediately upon the appointment of a successor Trustee as provided in the 2015 Series C Subordinated Indenture and acceptance of such appointment by such successor.
In case at any time the Trustee resigns or is removed or has become incapable of acting, or is adjudged as bankrupt or insolvent, or if a receiver, liquidator or conservator of the Trustee or of its property, is appointed, or if any public officer takes charge or control of the Trustee or of its property or affairs, a successor Trustee may be appointed by the Owners of a majority in principal amount of 2015 Series C Subordinate Bonds then Outstanding, and failing such an appointment the Authority shall appoint a successor to hold office until a successor Trustee shall be appointed by the Owners. The Trustee and each successor Trustee, if any, shall be a bank, a trust company, or a national banking association, doing business and having a corporate trust office in either New York, New York, Los Angeles, California or San Francisco, California and having capital stock and surplus aggregating at least $100,000,000, if there be such a bank, trust company or national banking association willing and able to accept the appointment on reasonable and customary terms and authorized by law to perform all the duties imposed on it by the 2015 Series C Subordinated Indenture.

The 2015 Series C Subordinated Indenture provides for the appointment by the Authority of a Paying Agent (which may include the Trustee). The Trustee, the Paying Agent or either or both of them, as may be appropriate, are a Fiduciary for purposes of the 2015 Series C Subordinated Indenture.

If no Event of Default is occurring, the Trustee shall perform only such duties as are specifically set forth in the 2015 Series C Subordinated Indenture. If an Event of Default has occurred and has not been cured or waived, the Trustee shall exercise such of the rights and powers vested in it by the 2015 Series C Subordinated Indenture, and use the same degree of care and skill in its exercise, as a prudent person would exercise or use under the circumstances in the conduct of his or her own affairs. Subject to the above, no Fiduciary shall be liable in connection with the performance of its duties under the 2015 Series C Subordinated Indenture except for its own negligence, misconduct or default.

The Authority is required to pay to each Fiduciary reasonable compensation for all services rendered under the 2015 Series C Subordinated Indenture and all reasonable expenses, charges, counsel fees and other disbursements, incurred in the performance of its powers and duties under the 2015 Series C Subordinated Indenture. Each Fiduciary has a lien on any and all funds held by it under the 2015 Series C Subordinated Indenture securing its right to compensation. The Authority also agrees to indemnify and save each Fiduciary, its officers, directors, employees and agents harmless, to the extent permitted by law, against any claims, costs, expenses or liabilities that it may incur in the exercise and performance of its powers and duties under the 2015 Series C Subordinated Indenture that are not due to its negligence, misconduct or default.

**Defeasance**

If the Authority shall pay or cause to be paid, or there shall otherwise be paid, to Owners of all 2015 Series C Subordinate Bonds the principal or Redemption Price (if applicable) of and interest due or to become due thereon, and to the Parity Swap Providers (if any) all of the amounts owed by the Authority under any Parity Swaps, at the times and in the manner stipulated therein and in the 2015 Series C Subordinated Indenture, then the lien of the 2015 Series C Subordinated Indenture and all covenants, agreements and other obligations of the Authority to the Owners and any such Parity Swap Providers, shall thereupon cease, terminate and become void and be discharged and satisfied, provided however that notwithstanding anything to the contrary in the 2015 Series C Subordinated Indenture, upon the defeasance of the 2015 Series C Subordinate Bonds, the Authority’s and the Trustee’s obligations with respect to execution, registration of transfer and exchange of 2015 Series C Subordinate Bonds under the 2015 Series C Subordinated Indenture shall not be discharged until such 2015 Series C Subordinate Bonds, and all accrued and unpaid interest, have been paid in full at the maturity thereof. In such event, the Trustee shall cause an accounting for such period or periods as shall be requested by the Authority to be prepared and filed with the Authority and, upon the request of the Authority shall execute and deliver
to the Authority all such instruments as may be desirable to evidence such discharge and satisfaction, and
the Fiduciaries shall pay over or deliver, as directed by the Authority, all moneys or securities held by
them pursuant to the 2015 Series C Subordinated Indenture that are not required for the payment of
principal or Redemption Price (if applicable) and interest due or to become due on the 2015 Series C
Subordinate Bonds not theretofore surrendered for such payment or redemption.

The 2015 Series C Subordinate Bonds (which may be less than all of the 2015 Series C
Subordinate Bonds then Outstanding) or interest installments for the payment or redemption of which
moneys shall have been set aside and shall be held in trust by the Paying Agents (through deposit
pursuant to the 2015 Series C Subordinated Indenture of funds for such payment or redemption or
otherwise) at the maturity, payment or redemption date thereof shall be deemed to have been paid within
the meaning and with the effect expressed in the above paragraph. Any Outstanding 2015 Series C
Subordinate Bonds shall prior to the maturity or redemption date thereof be deemed to have been paid
within the meaning and with the effect expressed in the above paragraph if (a) in case any of said 2015
Series C Subordinate Bonds are to be redeemed (if applicable) on any date prior to their maturity, the
Authority shall have given to the Trustee irrevocable instructions accepted in writing by the Trustee, as
provided in the 2015 Series C Subordinated Indenture, to mail a notice of redemption of such 2015
Series C Subordinate Bonds on said date, (b) there shall have been deposited with the Trustee either
moneys in an amount that shall be sufficient, or Defeasance Obligations (including any Defeasance
Obligations issued or held in book-entry form on the books of the Department of the Treasury of the
United States) the principal of and the interest on which when due will provide moneys that, together with
the moneys, if any, on deposit with the Trustee, shall be sufficient, in the opinion of an independent
certified public accountant or independent arbitrage consultant, to pay when due the principal or
Redemption Price (if applicable) and interest due and to become due on said 2015 Series C Subordinate
Bonds on and prior to the redemption date or maturity date thereof, as the case may be, and (c) in the
event such 2015 Series C Subordinate Bonds are not by their terms subject to redemption within the next
succeeding sixty (60) days, the Authority shall have given a trustee, which may be the Trustee, in form
satisfactory to such trustee, irrevocable instructions to mail, as soon as practicable, a notice to the
registered Owners of such 2015 Series C Subordinate Bonds a notice that the deposit required by (b)
above has been made with such trustee and that said 2015 Series C Subordinate Bonds are deemed to
have been paid in accordance with the 2015 Series C Subordinated Indenture and stating such maturity or
redemption date upon which moneys are to be available for the payment of the principal or Redemption
Price (if applicable) on such 2015 Series C Subordinate Bonds. Neither Defeasance Obligations nor
moneys deposited with the Trustee pursuant to the 2015 Series C Subordinated Indenture nor principal or
interest payments on any such Defeasance Obligations shall be withdrawn or used for any purpose other
than, and shall be held in trust for, the payment of the principal or Redemption Price (if applicable) and
interest on said 2015 Series C Subordinate Bonds; provided that any cash received from such principal or
interest payments on such Defeasance Obligations deposited with the Trustee, (A) to the extent such cash
will not be required at any time for such purpose, as determined by an independent certified public
accountant or independent arbitrage consultant, shall be paid over upon the direction of the Authority as
received by the Trustee, free and clear of any trust, lien, pledge or assignment securing said 2015 Series C
Subordinate Bonds or otherwise existing under the 2015 Series C Subordinated Indenture, and (B) to the
extent such cash will be required for such purpose at a later date, shall, to the extent practicable, be
reinvested pursuant to the direction of the Authority in Defeasance Obligations (including any Defeasance
Obligations issued or held in book-entry form on the books of the Department of the Treasury of the
United States) maturing at times and in amounts sufficient to pay when due the principal or Redemption
Price (if applicable) and interest to become due on said 2015 Series C Subordinate Bonds, on or prior to
such redemption date or maturity date thereof, as the case may be, and interest earned from such
reinvestments shall be paid over as received by the Trustee, free and clear of any lien, pledge or security
interest securing said 2015 Series C Subordinate Bonds or otherwise existing under the 2015 Series C
Subordinated Indenture.
Any request, consent, revocation of consent or other instrument that the 2015 Series C Subordinated Indenture may require or permit to be signed and executed by the Bondowners may be in one or more instruments of similar tenor, and shall be signed or executed by such Bondowners in person or by their attorneys or representatives, appointed in writing. Proof of (i) the execution of any such instrument, or of an instrument appointing any such attorney or representative, or (ii) the holding by any person of the 2015 Series C Subordinate Bonds shall be sufficient for any purpose of the 2015 Series C Subordinated Indenture (except as otherwise therein expressly provided) if made in accordance with the 2015 Series C Subordinated Indenture, or in any other manner satisfactory to the Trustee, which may nevertheless in its discretion require further or other proof in cases where it deems the same desirable.

Events of Default and Remedies

Each of the following constitute an Event of Default under the 2015 Series C Subordinated Indenture: (1) except as otherwise provided in the 2015 Series C Subordinated Indenture, the failure to pay the principal or Redemption Price (if applicable) of any 2015 Series C Subordinate Bond when due; (2) the failure to pay any interest installment on any 2015 Series C Subordinate Bond when due; (3) the continuation of a default by the Authority in the observance or performance of any other covenants, agreements or conditions contained in the 2015 Series C Subordinated Indenture or in the 2015 Series C Subordinate Bonds for 120 days after written notice thereof from the Trustee or the Owners of not less than 10% in principal amount of the 2015 Series C Subordinate Bonds then Outstanding; and (4) the occurrence of an Event of Default (as defined in the Senior Indenture) under the Senior Indenture.

Upon the occurrence of any Event of Default which has not been remedied, the Authority shall, if demanded in writing by the Trustee, account, as if it were the trustee of an express trust, for all Pledged Revenues and other moneys, securities and funds pledged or held under the 2015 Series C Subordinated Indenture. The Trustee shall apply all moneys, securities, funds and Pledged Revenues pledged to the benefit of the Owners of the 2015 Series C Subordinate Bonds and any Parity Swap Providers (a) received by the Trustee pursuant to any right given or action taken under the 2015 Series C Subordinated Indenture and (b) held by the Trustee pursuant and subject to the terms and conditions of the 2015 Series C Subordinated Indenture in the following order: first, to the payment of the reasonable fees and expenses of the Trustee for performance of its duties under the 2015 Series C Subordinated Indenture (including those of its counsel) and including those incurred during any period of default; second, to the payment to the persons entitled thereto of all installments of interest on the 2015 Series C Subordinate Bonds then due in the order in which such installments became due, together with accrued and unpaid interest on the 2015 Series C Subordinate Bonds theretofore called for redemption (if applicable), and, if the amount available shall not be sufficient to pay in full any installment or installments due on the same date, then to the payment thereof ratably, according to the amounts due thereon, to the persons entitled thereto, without any discrimination or preference; and third, to the payment to the persons entitled thereto of the unpaid principal or Redemption Price (if applicable) of any 2015 Series C Subordinate Bonds that shall have become due, whether at maturity or by call for redemption, and all obligations under any Parity Swaps that shall have become due and payable (with any termination payments due under any Parity Swaps being payable on a basis subordinate and junior to the payment of the principal or Redemption Price (if applicable) of any 2015 Series C Subordinate Bonds), in the order of their due dates, and, if the amount available shall not be sufficient to pay in full all the 2015 Series C Subordinate Bonds and any Parity Swaps (other than termination payments thereunder) due on any date, then to the payment thereof ratably, according to the amounts of principal or Redemption Price or payments due under any Parity Swaps (other than termination payments thereunder) due on such date, to the persons entitled thereto, without any discrimination or preference.

If an Event of Default has occurred and has not been remedied, the Trustee may, and upon written request of the Owners of not less than a majority in aggregate principal amount of the 2015 Series C Subordinated Indenture may require or permit to be signed and executed by the Bondowners may be in one or more instruments of similar tenor, and shall be signed or executed by such Bondowners in person or by their attorneys or representatives, appointed in writing. Proof of (i) the execution of any such instrument, or of an instrument appointing any such attorney or representative, or (ii) the holding by any person of the 2015 Series C Subordinate Bonds shall be sufficient for any purpose of the 2015 Series C Subordinated Indenture (except as otherwise therein expressly provided) if made in accordance with the 2015 Series C Subordinated Indenture, or in any other manner satisfactory to the Trustee, which may nevertheless in its discretion require further or other proof in cases where it deems the same desirable.
Subordinate Bonds Outstanding, to the extent indemnified as provided in the 2015 Series C Subordinated Indenture, shall, proceed to protect and enforce its rights and the rights of the Owners under the 2015 Series C Subordinated Indenture forthwith by a suit or suits in equity or at law, whether for the specific performance of any covenant in the 2015 Series C Subordinated Indenture, or in aid of the execution of any power granted in the 2015 Series C Subordinated Indenture or any remedy granted under the Act, or for an accounting against the Authority as if it were the trustee of an express trust, or in the enforcement of any other legal or equitable right as the Trustee, being advised by counsel, deems most effectual to enforce any of its rights or to perform any of its duties under the 2015 Series C Subordinated Indenture. Regardless of the happening of an Event of Default, the Trustee shall have the power to, but unless requested in writing by the Owners of a majority in principal amount of the 2015 Series C Subordinate Bonds then Outstanding and furnished with reasonable security and indemnity shall be under no obligation to, institute and maintain such suits and proceedings as it may be advised shall be necessary or expedient to prevent any impairment of the security under the 2015 Series C Subordinated Indenture or as it may be advised shall be necessary or expedient to preserve or protect the interests of the Trustee and of the Owners.

No Owner shall have any right to institute any suit, action or proceeding at law or in equity for the enforcement of any provision of the 2015 Series C Subordinated Indenture or the execution of any trust under the 2015 Series C Subordinated Indenture or for any remedy under the 2015 Series C Subordinated Indenture, unless (1) such Owner previously has given the Trustee written notice of the happening of an Event of Default as provided in the 2015 Series C Subordinated Indenture, (2) the Owners of at least a majority in aggregate principal amount of the 2015 Series C Subordinate Bonds then Outstanding have filed a written request with the Trustee and have offered the Trustee reasonable opportunity to exercise its powers or to institute such suit, action or proceeding in its own name, (3) there have been offered to the Trustee by such Owners adequate security and indemnity against its costs, expenses and liabilities to be incurred, and (4) the Trustee has refused to comply with such request for a period of sixty (60) days after receipt by it of such notice, request and offer of indemnity.

Notice of Default

The Trustee shall promptly mail notice of the occurrence of any Event of Default to each Owner of the 2015 Series C Subordinate Bonds then Outstanding.

Unclaimed Moneys

Any moneys held by a Fiduciary in trust for the payment and discharge of any of the principal of, Redemption Price (if applicable) of, or interest on any of the 2015 Series C Subordinate Bonds which remain unclaimed for one year after the date when the payment shall have become due and payable, shall be repaid by the Fiduciary to the Authority, as its absolute property and free from trust, and the Fiduciary shall thereupon be released and discharged with respect thereto and the Owners not yet paid shall look only to the Authority for the payment of such 2015 Series C Subordinate Bonds.

SUMMARY OF CERTAIN PROVISIONS OF THE TRANSMISSION SERVICE CONTRACTS

The following is a summary of certain provisions of the Transmission Service Contracts entered into between Southern California Public Power Authority (in this summary, “SCPPA”) and each of the Transmission Service Purchasers, which consist of the Department of Water and Power of The City of Los Angeles and the cities of Anaheim, Riverside, Pasadena, Burbank and Glendale. Except as described in this summary, all of the Transmission Service Contracts are identical in all material respects. This summary is not to be considered a full statement of the terms of such Transmission Service Contracts and
accordingly is qualified by reference thereto and is subject to the full text thereof. Capitalized terms not defined in this summary or in the Official Statement have the respective meanings set forth in the Transmission Service Contracts.

The Agreement

SCPPA and each of the Transmission Service Purchasers have entered into a Transmission Service Contract (the “Transmission Service Contract”) pursuant to which the Transmission Service Purchasers will contract with SCPPA for transmission service utilizing SCPPA Capacity so as to provide for transmission of capacity and energy from the Intermountain Power Project and other resources.

SCPPA intends to issue Bonds and Notes sufficient to finance or refinance the costs of acquiring SCPPA Capacity. The payments required to be made under the Transmission Service Contracts are to be pledged by SCPPA as security for the payment of such Bonds, and the interest thereon, subject to the application thereof to such purposes and on such terms as provided in the Senior Indenture.

Definitions

Agreements for the Acquisition of Capacity: The several Agreements for the Acquisition of Capacity between SCPPA and the Transmission Service Purchasers, as the same may be amended and supplemented from time to time in accordance with their terms.

Annual Budget: The budget adopted by the Board of Directors pursuant to the Transmission Service Contracts not less than 30 nor more than 45 days prior to the beginning of each Transmission Service Year, including any amendments thereto, which shall show a detailed estimate of the items for such Transmission Service Year upon which Monthly Transmission Costs for such Transmission Service Year are computed and all revenues, income or other funds to be applied to such costs, for and applicable to such Transmission Service Year.

Available Transmission Capability: At any point in time, the operating capability of the Transmission Project as determined in accordance with the IPP Power Sales Contracts.

Billing Statement: The written statement prepared (or caused to be prepared) each Month by SCPPA which shall be based upon the Annual Budget and which shall show for such Month the amount to be paid to the Trustee by the Transmission Service Purchasers in accordance with the provisions of the Transmission Service Contracts.

Bond Resolution: The resolution entitled “Power Supply Revenue Bond Resolution,” adopted by IPA on September 28, 1978, as heretofore amended and supplemented and as hereafter from time to time amended and supplemented in conformity with its provisions and the provisions of the IPP Power Sales Contracts.

Cost of Acquisition of Capacity: All costs and expenses of acquiring and financing or refinancing SCPPA Capacity. Such costs shall include all payments under the Southern Transmission System Agreement which are applied or are to be applied thereunder to the payment of the Cost of Acquisition and Construction, costs incurred by SCPPA in connection with the financing or refinancing of SCPPA Capacity and SCPPA Expenses. There shall be applied, as a credit against the Cost of Acquisition of Capacity, interest earned on investments, all if and to the extent held or paid into the SCPPA Construction Fund. Subject to the foregoing, Cost of Acquisition of Capacity shall include, but shall not be limited to, funds required for the following:
(1) The Cost of Acquisition and Construction, and any other amounts paid or to be paid to IPA pursuant to the Southern Transmission System Agreement;

(2) SCPPA Expenses;

(3) Financial and legal costs and expenses and such amount of reserves as are required by the Senior Indenture;

(4) Subject to the requirements of the Act, interest accruing in whole or in part on Bonds prior to and during construction of the Transmission Project and for such additional period, consistent with the Act, as SCPPA may reasonably determine to be necessary in accordance with the provisions of the Senior Indenture;

(5) Amounts, if any, required by the Senior Indenture to be paid from the proceeds of Bonds issued to finance the Cost of Acquisition of Capacity into the Debt Service Reserve Account in the Debt Service Fund or the Reserve and Contingency Fund or into any other funds or accounts established pursuant to the Senior Indenture;

(6) The payment of principal, premium, if any, and interest due (whether at the maturity of principal or at the due date of interest or upon redemption) of any Note;

(7) To the extent not included in Cost of Acquisition and Construction, all costs of insurance applicable to the period of construction of the Transmission Project;

(8) To the extent not included in Cost of Acquisition and Construction, all costs relating to injury and damage claims arising out of the construction of the Transmission Project, less proceeds of insurance; and

(9) All other costs properly allocable to the acquisition and financing or refinancing of SCPPA Capacity.

Date of Firm Operation: With respect to the Initial Facilities, the initial date recommended by the Project Manager and determined by the Coordinating Committee on which the Initial Facilities can reasonably be expected to operate reliably.

FERC Accounts: The Federal Energy Regulatory Commission Uniform Systems of Accounts prescribed for Class A and Class B Public Utilities and licensees, as the same may be modified, supplemented or amended from time to time.

Initial Facilities: The Southern Transmission System as described in the Transmission Service Contracts. Such description shall be amended from time to time to conform to the description of the Southern Transmission System in the IPP Power Sales Contracts.

Monthly Transmission Costs: All of SCPPA’s costs, to the extent attributable to SCPPA Capacity and to the extent not paid from the proceeds of Bonds or Notes, resulting from the acquisition and financing or refinancing of SCPPA Capacity. There shall be applied, as a credit against Monthly Transmission Costs, any interest earned on investments if and to the extent not credited against the Cost of Acquisition of Capacity. Monthly Transmission Costs shall include, but not be limited to, the items of cost and expense referred to in the Transmission Service Contracts that are attributable to SCPPA Capacity and are accrued or paid during each Month of each Transmission Service Year. In the event any Transmission Service Year shall cover fewer than 12 Months, the fraction expressed in subparagraphs (4),
(5) and (6) below shall be adjusted accordingly, and, in the event of any revision of the Annual Budget after the commencement of any Transmission Service Year, the amount determined pursuant to subparagraphs (4), (5) and (6) below shall be appropriately adjusted so that any increase or decrease in the portion of the Annual Budget applicable to said subparagraphs shall be evenly apportioned over the remaining Months of such Transmission Service Year. Monthly Transmission Costs shall include without duplication:

1. The Monthly Power Costs allocable to the Transmission Project, pursuant to the IPP Power Sales Contracts.

2. The amount which is required under the Senior Indenture to be paid or deposited during such month into any funds or accounts established by the Senior Indenture for Debt Service and for any reserve requirements for Bonds.

3. The amount which is required to be paid or deposited during such Month into any fund or account established by the Senior Indenture or otherwise for the payment of interest (net of any interest subsidy with respect to Bonds paid to or for the account of SCPPA by any governmental body or agency) on Notes.

4. One-twelfth of the amount (not otherwise included under any item described under this definition of Monthly Transmission Costs) which is required under the Senior Indenture to be paid or deposited during such Transmission Service Year into any other fund established by the Senior Indenture, and shall include, without limitation, amounts required to make up a deficiency in any such fund whether or not resulting from a default in payments by any Transmission Service Purchaser of amounts due under any Transmission Service Contract.

5. One-twelfth of the amount necessary during such Transmission Service Year to pay costs of providing transmission service during such Transmission Service Year (including SCPPA Expenses) to the extent not included in subparagraph (1) hereof.

6. One-twelfth of the amount necessary during such Transmission Service Year to pay or provide reserves for all taxes required to be paid by SCPPA with respect to SCPPA Capacity to the extent not included in subparagraph (1) hereof.

**SCPPA Capacity**: The right of SCPPA to capacity in the Transmission Project, pursuant to the Agreements for the Acquisition of Capacity.

**SCPPA Expenses**: The costs, expenses and fees incurred by SCPPA in carrying out its duties, responsibilities and obligations, and exercising its rights, under the Act and the Transmission Project Agreements.

**Southern Transmission System Agreement**: The Southern Transmission System Agreement between SCPPA and IPA, as the same may be hereafter amended or supplemented.

**Transmission Project**: The Initial Facilities and any Capital Improvements.

**Transmission Project Agreements**: The Senior Indenture, the Transmission Service Contracts, the Southern Transmission System Agreement, the Agreements for the Acquisition of Capacity, the IPP Power Sales Contracts, the Bond Resolution of IPA and any other contract designated a Transmission Project Agreement by the Board of Directors.
**Transmission Service Share:** The percentage of the total transmission service utilizing SCPPA Capacity to which a particular Transmission Service Purchaser is entitled in accordance with the terms of its Transmission Service Contract.

**Transmission Service Shares**

SCPPA will provide transmission service utilizing SCPPA Capacity to the Transmission Service Purchasers in accordance with the following:

1. All transmission service utilizing SCPPA Capacity shall be scheduled in accordance with the practices and procedures established pursuant to the Transmission Project Agreements. At all times after the Date of Firm Operation each Transmission Service Purchaser shall be entitled to schedule transmission service utilizing SCPPA Capacity up to the amount obtained by multiplying its Transmission Service Share by the Available Transmission Capability.

2. Operation of the Transmission Project shall be subject to scheduled outages or curtailments and restrictions imposed by any regulatory authority and Uncontrollable Forces.

3. It is the obligation of each Transmission Service Purchaser, at its own expense, to secure access to the main AC bus adjacent to each converter terminal of the Transmission Project, which are the terminal points for the Transmission Project. Such access may be by physical connection or by contract path. In no event shall SCPPA have any obligation to provide transmission or wheeling services from such terminal points to the electric system of the Transmission Service Purchaser.

**Pledge of Payments**

All payments required to be made by the Transmission Service Purchasers in accordance with or pursuant to any provision of the Transmission Service Contracts, are pledged by SCPPA to secure the payment of the Bonds, the interest thereon, and the interest on the Notes subject to the application thereof to such purposes and on such terms as provided in the Senior Indenture securing such Bonds. SCPPA, in the Transmission Service Contracts, assigns the payments referenced in the Transmission Service Contracts to the Trustee and directs each Transmission Service Purchaser to pay such amounts directly to the Trustee.

**Nature of Obligation**

Each Transmission Service Purchaser is obligated to make payments required under its Transmission Service Contract solely from its electric revenue funds as a cost of transmission service and an operating expense of its electric utility system. Each such Transmission Service Purchaser has covenanted to include in its annual electric system budget for each fiscal year during the term of its Transmission Service Contract an appropriation from the revenues of its electric system sufficient to pay all amounts required to be paid during such fiscal year under such Transmission Service Contract. The obligations, which are several and not joint, to make payments of Monthly Transmission Costs under the respective Transmission Service Contracts are not subject to reduction or offset if the Transmission Project or any part thereof is not completed, is not operating or operable or if its service is suspended, interfered with, reduced, curtailed or terminated in whole or in part. In addition, the Transmission Service Purchasers’ obligations under the Transmission Service Contracts are not subject to any reduction or offset and are not conditional upon the performance or nonperformance by any party of any agreement for any cause whatever.
Term

The Transmission Service Contracts shall constitute a binding obligation of the parties thereto from and after the effective date, and the term of such Transmission Service Contracts shall end on June 15, 2027 or such later date upon which all Bonds and Notes and the interest thereon shall have been paid in full or adequate provisions for such payment shall have been made, unless terminated sooner in accordance with the provisions for termination or amendment described below.

Required Payments

For a discussion on Monthly Transmission Costs and the payment obligations of the respective Transmission Service Purchasers with respect thereto, see “SECURITY AND SOURCES OF PAYMENT FOR THE SENIOR BONDS AND THE SUBORDINATE BONDS – Transmission Service Contracts” in the front part of this Official Statement.

Rate Covenants of Transmission Service Purchasers

Each Transmission Service Purchaser has covenanted in its Transmission Service Contract to establish, maintain and collect rates and charges for the electric service it furnishes so as to provide revenues which, together with its available electric system reserves, are sufficient to enable it to pay all amounts payable when due under its Transmission Service Contract and to pay all other amounts payable from, and all lawful charges against or liens on, its electric system revenues.

Board of Directors

SCPPA is administered by a Board of Directors comprised of the chief executive officer (or his or her designee) of the electric utility of each member of SCPPA. The Transmission Service Purchasers are entitled to participate in Transmission Project Matters in accordance with voting rights given to them as a member of SCPPA. See “SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY - Organization and Management” in the front part of this Official Statement. SCPPA, through its Board of Directors, has the following duties and responsibilities, among others: (1) provide liaison among the Transmission Service Purchasers; (2) attempt to resolve any disputes among SCPPA, the Transmission Service Purchasers, the Agent, the Project Manager or the Operating Agent relating to the Transmission Project; (3) review, modify and approve (i) the practices and procedures to be followed by the Transmission Service Purchasers relating to the scheduling and controlling of capacity and energy from the Transmission Project, (ii) all Capital Improvements, the budgets therefor and the provisions for financing thereof and (iii) all amendments and supplements to the Transmission Project insurance program; (4) approve all consultants or advisors on financial and legal matters that may be retained by SCPPA; (5) approve the issuance of each series of Bonds and evidences of indebtedness issued in anticipation of the issuance of Bonds; and (6) perform other functions provided for in the Transmission Service Contracts and the other Transmission Project Agreements.

Restrictions on Disposition

A Transmission Service Purchaser may not sell, lease or otherwise dispose of all or substantially all of its electric system except upon the satisfaction of certain conditions, including, among others, that: (1) the Transmission Service Purchaser assigns its interest under its Transmission Service Contract to the purchaser or lessee of its electric system and said purchaser or lessee assumes all obligations of the Transmission Service Purchaser under the Transmission Service Contract; (2) the senior debt of the purchaser or lessee is rated in one of the two highest categories by at least one nationally recognized bond rating agency; (3) an independent engineer selected by SCPPA delivers an opinion that such purchaser or
lessee is reasonably able to charge and collect rates and charges required to meet its obligations under the Transmission Service Contract; (4) it is determined by the Board of Directors that the disposition will not adversely affect the value of such Transmission Service Contract as security for the Bonds; and (5) Bond Counsel has rendered an opinion that such disposition will not adversely affect the exemption from federal income taxation of interest payable on the Bonds (if applicable).

**Defaults and Remedies**

The failure of a Transmission Service Purchaser to perform any of its obligations, including the obligation to make required payments, under its Transmission Service Contract will constitute a default. In the event of a default or inability to perform by a Transmission Service Purchaser under its Transmission Service Contract, SCPPA may proceed to enforce the Transmission Service Purchaser’s covenants or obligations thereunder, or may seek damages or injunctive relief for the breach thereof, by action at law or equity, or if a payment due under the Transmission Service Contract remains unpaid when due, SCPPA may, upon 90 days’ written notice to the Transmission Service Purchaser, discontinue the delivery of capacity and energy to such Transmission Service Purchaser. The discontinuance of transmission service to a defaulting Transmission Service Purchaser by SCPPA will not reduce the obligation of such Transmission Service Purchaser to make payments under its Transmission Service Contract. In the event the delivery of capacity and energy to a Transmission Service Purchaser in default is discontinued, SCPPA shall transfer to all other Transmission Service Purchasers which are not in default and which so request, a pro rata portion of the defaulting Transmission Service Purchaser’s rights to delivery of capacity and energy. In the case of such a transfer, the Transmission Service Purchasers accepting additional rights to delivery of capacity and energy and use of Transmission Project facilities shall assume the defaulting Transmission Service Purchaser’s obligations with respect to the rights which are transferred to them. In the event less than all of a defaulting Transmission Service Purchaser’s rights to delivery of capacity and energy is transferred to nondefaulting Transmission Service Purchasers, SCPPA shall, to the extent possible, dispose of such remaining rights on the best terms readily available, and in such a manner as, in the opinion of Bond Counsel, does not adversely affect the eligibility for exemption from federal income taxes of the interest payable on the Bonds (if applicable). The obligation of the defaulting Transmission Service Purchaser to SCPPA shall be reduced to the extent that SCPPA receives payments with respect to the rights of such Transmission Service Purchaser which are transferred. For a further discussion of remedies, see “SECURITY AND SOURCES OF PAYMENT FOR THE SENIOR BONDS AND THE SUBORDINATE BONDS - Transmission Service Contracts” in the front part of this Official Statement.

**Termination or Amendment**

As long as any Bonds issued under the Senior Indenture or any Notes issued under a Note Resolution are outstanding or until provision has been made for the payment of any Bonds and Notes outstanding in accordance with the Senior Indenture, the Transmission Service Contracts may not be terminated or amended in any manner which will reduce the amount of or extend the time for the payments which are pledged as security for the Bonds or the Notes or which will impair or adversely affect the rights of the holders of the Bonds or the Notes. Each Transmission Service Contract also provides that SCPPA may not, without the written consent of each of the Transmission Service Purchasers, amend or supplement the Senior Indenture (except to provide for the issuance of additional Bonds), to affect the rights and obligations of the Transmission Service Purchasers under the Transmission Service Contracts or to the disadvantage of the Transmission Service Purchasers or to result in increased Monthly Transmission Costs to the Transmission Service Purchasers.
Contracts Subject to Senior Indenture

It has been recognized by the Transmission Service Purchasers in the Transmission Service Contracts that SCPPA, in acquiring, financing or refinancing of SCPPA Capacity, must comply with the requirements of the Senior Indenture, the other Transmission Project Agreements and all licenses, permits and regulatory approvals necessary therefor. The Transmission Service Purchasers have therefore agreed that the Transmission Service Contracts are subject to the provisions of the Senior Indenture, the other Transmission Project Agreements and such licenses, permits and approvals.

SUMMARY OF CERTAIN PROVISIONS OF THE IPP POWER SALES CONTRACTS

The following is a summary of certain provisions of the IPP Power Sales Contracts, as amended (including the amendments effected by the Amendatory Power Sales Contracts), entered into between IPA and each of the IPP Purchasers. Except as described in this summary, all of the IPP Power Sales Contracts are identical in all material respects. This summary is not to be considered a full statement of the terms of such IPP Power Sales Contracts and accordingly is qualified by reference thereto and subject to the full text thereof. Capitalized terms not defined in the Official Statement have the meanings set forth in the IPP Power Sales Contracts.

Entitlement to Capacity

Each IPP Purchaser is entitled to receive under its IPP Power Sales Contract capacity and energy from the Generation Station up to its Generation Entitlement Share, as specified in its IPP Power Sales Contract, of the available capacity of the Generation Station. An IPP Purchaser may arrange to dispose of capacity or energy from IPP to which it is entitled, but any such arrangements will not affect its obligations under its IPP Power Sales Contract. Each IPP Purchaser’s entitlement to the use of the operating capabilities of the Southern and Northern Transmission Systems shall be determined by dividing the portion of such IPP Purchaser’s Generation Entitlement Share to be delivered at Points of Delivery on the Southern Transmission System, in the case of the Southern Transmission System, and at Points of Delivery on the Northern Transmission System, in the case of the Northern Transmission System, by the aggregate of those portions of all IPP Purchasers’ Generation Entitlement Shares to be delivered at the Points of Delivery on the Southern Transmission System and the Northern Transmission System, respectively. IPP Purchasers having unused entitlements to transmission capacity may agree to allow other IPP Purchasers to use such entitlement except that no IPP Purchaser may use the transmission system in excess of its respective entitlement share if such use would adversely affect the eligibility for federal income tax exemption of the interest payable on the bonds issued by IPA.

Nature of Obligation

Each IPP Purchaser which is a municipally owned electric system is obligated to make the payments required under its IPP Power Sales Contract solely from the revenues of its electric system as a cost of purchased electric capacity and energy and an operating expense. Each such IPP Purchaser has covenanted to include in its annual power system budget for each fiscal year during the term of its IPP Power Sales Contract an appropriation from the revenues of its electric system sufficient to pay all amounts required to be paid during such fiscal year under such IPP Power Sales Contract. The IPP Power Sales Contracts constitute a general obligation of each IPP Purchaser which is not a municipally owned electric system. The IPP Purchasers’ obligations, which are several and not joint, to make payments of Monthly Power Costs under their respective IPP Power Sales Contracts are not subject to reduction or offset if IPP is not completed, operating or operable or if its output (and as a result, the capacity available to each of the IPP Purchasers) is suspended, interrupted, interfered with, reduced or curtailed or terminated in whole or in part. In addition, the IPP Purchasers’ payment obligations under the IPP Power
Sales Contracts are not conditioned upon the performance by IPA or any other party (including any other IPP Purchaser) of contractual or other obligations and are not subject to any reduction or offset in the event of any default by IPA in the performance of its obligations under the IPP Power Sales Contracts.

**Term**

The term of each IPP Power Sales Contract has commenced and will end on June 15, 2027, unless terminated sooner in accordance with the provisions for termination or amendment described below.

**Rate Covenants of Municipal Purchasers**

Each IPP Purchaser which is a municipally owned electric system has covenanted in its IPP Power Sales Contract to establish, maintain and collect rates and charges for the electric service it furnishes so as to provide revenues which, together with its available electric system reserves, are sufficient to enable it to pay to IPA all amounts payable under its IPP Power Sales Contract and to pay all other amounts payable from, and all lawful charges against or liens on, its electric system revenues.

**IPP Coordinating Committee**

The IPP Power Sales Contracts provide for the establishment of an IPP Coordinating Committee composed of representatives of the IPP Purchasers and IPA which is to (a) provide liaison among IPA and the IPP Purchasers, (b) make recommendations to the Project Manager and Operating Agent with respect to the construction and operation of the Project, (c) review, modify and approve the practices and procedures formulated by the Project Manager and Operating Agent under the Construction Management and Operating Agreement, including procedures for the scheduling and controlling of capacity and energy from IPP and procedures with respect to operation of generating units and fuel storage, the schedule of planned maintenance outages, all budgets and revisions thereof prepared and submitted by the Project Manager or Operating Agent pursuant to the Construction Management and Operating Agreement, all Capital Improvements and the budgets therefor and provisions for financing thereof, the insurance program with respect to IPP and revisions to the description of IPP contained in the IPP Power Sales Contracts, (d) approve all consultants or advisors on financial matters, including bond counsel, that may be retained by IPA, (e) make recommendations to IPA concerning the issuance of bonds and evidences of indebtedness issued in anticipation of the issuance of bonds and (f) perform other functions provided for in the IPP Power Sales Contracts and the Construction Management and Operating Agreement. No action by the IPP Coordinating Committee pursuant to its authority under the IPP Power Sales Contracts or otherwise shall require IPA to act in a manner inconsistent with, or refrain from acting as required by, the Bond Resolution of IPA or any applicable licenses, permits or regulatory provisions.

Any action taken by the IPP Coordinating Committee shall require an affirmative decision of representatives of IPP Purchasers having Voting Rights aggregating at least 80%. If the IPP Coordinating Committee is unable to, or fails to, agree and act with respect to the review, modification or approval of certain actions of the Project Manager or Operating Agent after a reasonable opportunity to do so or within the time limits specified in the Construction Management and Operating Agreement, the Project Manager or Operating Agent may take such actions subject to the terms of the Construction Management and Operating Agreement. The term Voting Rights means at any particular time with respect to an IPP Purchaser, such Purchaser’s Generation Entitlement Share in effect at such time under its IPP Power Sales Contract.
Restrictions on Disposition

An IPP Purchaser may not sell, lease or otherwise dispose of all or substantially all of its electric system except upon the satisfaction of certain conditions, including, among others, that (i) the IPP Purchaser assigns its interest under its IPP Power Sales Contract to the purchaser or lessee of its electric system and said purchaser or lessee assumes all obligations of the IPP Purchaser under the IPP Power Sales Contract, (ii) the senior debt of the purchaser or lessee is rated in one of the two highest categories by at least one nationally recognized bond rating agency and (iii) it is determined by IPA that the disposition will not adversely affect the value of such IPP Power Sales Contract as security for the bonds or affect the eligibility for tax exempt status of bonds issued by IPA. In addition, an IPP Purchaser may not sell, assign or otherwise dispose of any portion of its Generation Entitlement Share or the capacity rights granted under its Purchaser’s IPP Power Sales Contract in the Northern Transmission System or the Southern Transmission System except if it is determined by IPA that the disposition will not adversely affect the eligibility for exemption from federal income taxes of interest on the bonds issued by IPA.

Defaults and Remedies

The failure of an IPP Purchaser to perform any of its obligations, including the obligation to make required payments under its IPP Power Sales Contract, will constitute a default. In the event of a default or inability to perform by an IPP Purchaser under its IPP Power Sales Contract, IPA may proceed to enforce the IPP Purchaser’s covenants or obligations thereunder, or seek damages for the breach thereof, by action at law or equity, or if a payment due under the IPP Power Sales Contract remains unpaid when due, IPA may, upon 120 days' written notice to the IPP Purchaser, discontinue the delivery of capacity and energy to, and the use of IPP facilities by, such IPP Purchaser while the default continues. Except as a result of a transfer of the defaulting IPP Purchaser’s rights to delivery of capacity and energy and the use of IPP facilities described below, the discontinuance of delivery of capacity and energy to, and the use of IPP facilities by, a defaulting IPP Purchaser by IPA will not reduce the obligation of such IPP Purchaser to make payments under its IPP Power Sales Contract.

In the event the delivery of capacity and energy to, and use of IPP facilities by, an IPP Purchaser in default is discontinued, IPA shall transfer to all other IPP Purchasers which are not in default and which so request, a pro rata portion of a defaulting IPP Purchaser’s rights to delivery of capacity and energy and use of IPP facilities. In the case of such a transfer, the IPP Purchasers accepting additional rights to delivery of capacity and energy and use of IPP facilities shall assume the defaulting IPP Purchaser’s obligations with respect to the rights which are transferred to them, other than the obligation to cure any deficiency in payment which may have occurred prior to such transfer. In the event less than all of a defaulting IPP Purchaser’s rights to delivery of capacity and energy and use of IPP facilities is transferred to non-defaulting IPP Purchasers, IPA shall, to the extent possible, dispose of such remaining rights on the best terms readily available in accordance with procedures formulated by the IPP Coordinating Committee, and in such a manner as does not adversely affect the eligibility for exemption from federal income taxes of the interest payable on the bonds issued by IPA. The obligation of the defaulting IPP Purchaser to IPA shall be reduced to the extent that IPA receives payments with respect to the rights of such IPP Purchaser which are transferred.

Termination or Amendment

As long as any bonds issued under the Bond Resolution of IPA are outstanding or until provision has been made for the payment of any bonds outstanding in accordance with the Bond Resolution of IPA, the IPP Power Sales Contracts may not be terminated or amended in any manner which will reduce the amount of or extend the time for the payments which are pledged as security for the bonds issued by IPA or which will impair or adversely affect the rights of the holders of such bonds. Each IPP Power Sales
Contract also provides that IPA may not, without the consent of each of the IPP Purchasers, amend or supplement the IPA Bond Resolution (except to provide for the issuance of additional bonds or Subordinated Indebtedness), to affect the rights and obligations of the IPP Purchasers under the IPP Power Sales Contracts or to be to the disadvantage of the IPP Purchasers or to result in increased Monthly Power Costs to the IPP Purchasers.

Contracts Subject to Bond Resolution

It has been recognized by the IPP Purchasers in the IPP Power Sales Contracts that IPA, in financing, acquiring, constructing and operating the Project, must comply with the requirements of the IPA Bond Resolution and all licenses, permits and regulatory approvals necessary therefor, and the IPP Purchasers have therefore agreed that the IPP Power Sales Contracts are subject to the provisions of the IPA Bond Resolution and such licenses, permits and approvals.

Payments-In-Aid of Construction

If requested by IPA, one or more IPP Purchasers or an agency acting on its or their behalf may agree to make payments-in-aid of construction for the Generation Station. The California Purchasers and the Utah Purchasers or any entity acting on their respective behalf may agree to make payments-in-aid of construction for the Southern Transmission System and the Northern Transmission System, respectively. All payments-in-aid of construction will be deposited in the account in the Construction Fund relating to the facility with respect to which such payments are being made and, subject to the lien and pledge of and covenants under the IPA Bond Resolution with respect to such Fund, all such deposits will be used by IPA for the payment of the Cost of Acquisition and Construction with respect to such facility. The payments-in-aid of construction will not change or otherwise affect IPA’s ownership of such facility or of IPP or any of the rights and obligations of IPA or the IPP Purchasers under the IPP Power Sales Contracts.

Use and Disposition of Certain Facilities

In recognition of the fact that IPP consists of certain rights, properties and facilities that could be used in connection with the construction and operation at the IPP site of additional generating units or transmission facilities, IPA may, with the approval of the IPP Coordinating Committee, sell, lease or otherwise make available such rights, properties and facilities for such construction or operation of other units or facilities at the IPP site. All amounts received shall be credited against Cost of Acquisition and Construction or Monthly Power Costs, as appropriate. No such disposition may interfere with the construction and operation of IPP or adversely affect the eligibility for federal income tax exemption of the interest payable on the bonds issued by IPA.

Expansion of Southern Transmission System

Any proposal for a major expansion of the Southern Transmission System is to be initiated by the IPP Coordinating Committee. Such proposal must comply with the Project Agreements and must provide that, subject to compliance with Utah law, the IPP Purchasers having entitlements to the Southern Transmission System under their respective IPP Power Sales Contracts will have the right to participate in the additional capacity of such expansion in proportion to their respective entitlements shares. Upon approval of any such proposal by IPA and the IPP Coordinating Committee, IPA will use its best efforts to proceed with the development of such expansion.
Certain Interconnection Agreements

The IPP Purchasers agree that IPA may comply with the requirements of the Mona Interconnection Agreement or other agreements approved by the IPP Coordinating Committee with respect to furnishing start up and black start power from IPP. All amounts received by IPA for furnishing such service shall be credited against Monthly Power Costs.

Transmission Service

IPP Purchasers with contractual rights in the Northern Transmission System agree that IPA may agree with UP&L to provide UP&L with such transmission service over portions of the Northern Transmission System as necessary in order to furnish UP&L with its Generation Entitlement Share. Subject to contractual rights with respect to the Northern Transmission System, IPA may schedule the unused capacity of such System for transmission service for other utilities. All amounts received by IPA for furnishing such service shall be credited against Monthly Power Costs.

Insurance Provisions

IPA will take reasonable and prudent steps to maintain properly designed and properly underwritten IPP property and casualty insurance programs during the construction phase of IPP and will design and arrange underwriting for property and casualty insurance programs for the operating phase of IPP. IPA will make every economically feasible effort to incorporate into the operation phase of IPP property insurance program extra-expense and business interruption coverage tied to all perils covered by the property insurance program and covering losses resulting from failure or interruption of the fuel supply for IPP.

SUMMARY OF CERTAIN PROVISIONS OF THE AGREEMENTS FOR THE ACQUISITION OF CAPACITY

The following is a summary of certain provisions of the Agreements for the Acquisition of Capacity (the “Acquisition Agreements”). This summary is not to be considered a full statement of the terms of the Acquisition Agreements and accordingly is qualified by reference thereto and is subject to the full text thereof. Capitalized terms not defined in this summary or in the Official Statement have the respective meanings set forth in the Acquisition Agreements.

Assignment of Capacity

Each Transmission Project Participant (consisting of the Department of Water and Power of The City of Los Angeles and the California cities of Anaheim, Riverside, Pasadena, Burbank and Glendale) and Southern California Public Power Authority (in this summary, “SCPPA”) have entered into an Acquisition Agreement pursuant to which each Transmission Project Participant has assigned its right to capacity in the Transmission Project to SCPPA and SCPPA has agreed to issue bonds, notes, or other evidences of indebtedness and to make payments-in-aid of construction of the Transmission Project to the Intermountain Power Agency (“IPA”).

Pursuant to the Acquisition Agreements, the Transmission Project Participants have assigned, transferred, conveyed, set over and relinquished to SCPPA in accordance with the Acquisition Agreements all of the Transmission Project Participants’ rights and interests in the Southern Transmission System in accordance with the IPP Power Sales Contracts. Such rights and interests consist of the Transmission Project Participants’ rights to capacity of the Southern Transmission System and all of the
Transmission Project Participants’ contract rights under the IPP Power Sales Contracts relating to the Southern Transmission System.

**Nature of Obligation**

SCPPA in the Acquisition Agreements agrees to issue bonds, notes or other evidences of indebtedness to provide funds to make payments-in-aid of construction with respect to the Southern Transmission System on behalf of the Transmission Project Participants pursuant to the terms of the Southern Transmission Agreement.

The Transmission Project Participants in the Acquisition Agreements agree that all payments of Monthly Power Costs with respect to the Southern Transmission System to be made by the Transmission Project Participants, which shall be made by SCPPA to IPA pursuant to the Southern Transmission System Agreement and received by IPA, shall be applied in discharge of the Transmission Project Participants’ obligation to make such payments of Monthly Power Costs under the IPP Power Sales Contracts, and the Transmission Project Participants’ obligation to pay such Monthly Power Costs shall be discharged only to the extent of such receipt. The obligation of the Transmission Project Participants to pay Monthly Power Costs under the IPP Power Sales Contracts shall continue and shall not otherwise be affected by the Southern Transmission System Agreement or by the Acquisition Agreements, except as discharged as provided in the Acquisition Agreements.

**Assignment of Transmission Project Participants’ Interests**

SCPPA and the Transmission Project Participants recognize that the Transmission Project Participants in accordance with the IPP Power Sales Contract have entered into or may enter into agreements with other entities pursuant to which such entities shall have rights, including the right to use capacity in the Southern Transmission System available to the Transmission Project Participants which may be in excess of the needs of the Transmission Project Participants which exist from time to time. The assignment under the Acquisition Agreements of the Transmission Project Participants’ rights and interests shall not affect the rights of any such entity or entities as aforesaid. It is further recognized that such rights of said entities may, if exercised or otherwise effectuated, result in rights of such entities with respect to the Transmission Project Participants’ Transmission Service Share. SCPPA shall, on behalf of the Transmission Project Participants, provide portions of the Transmission Project Participants’ Transmission Service Share to the entities on such terms as shall be agreed upon by the Transmission Project Participants consistent with the rights of such entities; provided, however, that no such arrangement shall release the Transmission Project Participants from any obligation under the Acquisition Agreements or under the Transmission Service Contracts.

The Acquisition Agreements became effective upon the first issuance by SCPPA of bonds, notes or other evidences of indebtedness to finance the acquisition of capacity rights in the Southern Transmission System.

**Amendment or Termination**

The Acquisition Agreements shall terminate concurrently with the termination of the Transmission Service Contracts between SCPPA and the Transmission Project Participants. Upon such termination, the rights and interests of SCPPA derived under the Acquisition Agreements shall cease and terminate and such rights and interests shall revert to the Transmission Project Participants.

The Transmission Project Participants agree that they will not consent to any amendment to the IPP Power Sales Contracts without the prior written consent of SCPPA.
SUMMARY OF CERTAIN PROVISIONS OF THE SOUTHERN TRANSMISSION SYSTEM AGREEMENT

The following is a summary of certain provisions of the Southern Transmission System Agreement, dated as of May 1, 1983, between Intermountain Power Agency ("IPA") and Southern California Public Power Authority (in this summary, "SCPPA"), as amended by the First Amendment to Southern Transmission System Agreement, dated as of November 1, 2008 (as so amended, the "STS Agreement"). This summary is not to be considered a full statement of the terms of the STS Agreement and accordingly is qualified by reference thereto and is subject to the full text thereof. Capitalized terms not defined in this summary or in the Official Statement have the respective meanings set forth in the STS Agreement.

Definitions

Agreements for the Acquisition of Capacity: The several Agreements for the Acquisition of Capacity between SCPPA and the Transmission Project Participants, as the same may be amended and supplemented from time to time in accordance with their terms.

Billing Statement: The written statement prepared or caused to be prepared each Month by IPA which shall be based upon the Annual Budget and which shall show for such Month the amount to be paid to IPA by each Transmission Project Participant and shall indicate the Monthly Power Costs allocated to the Transmission Project pursuant to the IPP Power Sales Contracts.


Construction Management and Operating Agreement: The Construction Management and Operating Agreement entered into between IPA and the Department of Water and Power of The City of Los Angeles relating to the construction and operation of IPP as from time to time amended and supplemented in conformity with the provisions of the IPP Power Sales Contracts.

SCPPA First Bonding Date: The date upon which SCPPA first issued and delivered bonds pursuant to the SCPPA Indenture of Trust to finance its payments-in-aid of construction for the Southern Transmission Initial Facilities, and, as applicable to the STS Upgrade Project, (i) the date upon which SCPPA first issued and delivered bonds, notes or other evidences of indebtedness to finance its payments-in-aid of construction for the STS Upgrade Project or (ii) the date upon which SCPPA first deposited in the SCPPA Transmission Project Construction Fund an amount from its available funds to provide for its payments-in-aid of construction for the STS Upgrade Project, whichever date shall be earlier.

Southern Transmission Capital Improvements: Capital Improvements (as defined in the IPP Power Sales Contracts) to the extent related to the Southern Transmission Initial Facilities and expressly including the STS Upgrade Project.

Southern Transmission Cost of Acquisition and Construction: All costs and expenses of planning, designing, acquiring, constructing, installing and financing the Transmission Project, placing the Transmission Project in operation, disposal of the Transmission Project, and obtaining governmental approvals, certificates, permits and licenses with respect thereto paid or incurred by IPA (all as further defined in the IPP Power Sales Contracts).
Southern Transmission Initial Facilities: The Southern Transmission System which consists of DC transmission and conversion facilities necessary to deliver capacity and energy from the Intermountain Power Project Generation Station to the point of delivery at Adelanto. Such facilities shall terminate at appropriate switchracks and shall include rights-of-way, a microwave communication system, and all other buildings, structures, facilities and appurtenances which shall be necessary or incidental in the useful construction and operation of such facilities.

STS Upgrade Project: The additions and improvements to and renewals of the Southern Transmission System that provided for an increase of the capacity of the Transmission Project from 1920 MW to 2400 MW.


Transmission Project Participant: Each of the following entities, together with their respective successors and assigns: Department of Water and Power of The City of Los Angeles; City of Anaheim; City of Riverside; City of Pasadena; City of Burbank; and City of Glendale.

Transmission Service Contracts: The several Transmission Service Contracts, dated as of May 1, 1983, between SCPPA and the Transmission Project Participants, as the same may be amended and supplemented from time to time in accordance with their terms and the terms of SCPPA’s Indenture of Trust.

The STS Agreement

SCPPA and IPA have entered into the STS Agreement pursuant to which SCPPA is able to issue bonds, notes or other evidences of indebtedness to provide funds to fulfill its obligation to make payments-in-aid of construction with respect to the Transmission Project by making payments to IPA in accordance with the terms of the STS Agreement.

Reports

IPA will prepare and issue to SCPPA copies of all information and reports relating to the Transmission Project required to be provided to the Transmission Project Participants in accordance with the IPP Power Sales Contracts, which shall include the following reports:

1. Financial and operating statements relating to the Transmission Project.
2. Status of Annual Budget.
4. Analysis of operations relating to the Transmission Project.

Performance of IPA Obligations by Others

Pursuant to the Construction Management and Operating Agreement, certain of the obligations and covenants of IPA under the IPP Power Sales Contracts and the IPA Bond Resolution will be performed and complied with, on behalf of IPA, by the Project Manager and Operating Agent under the Construction Management and Operating Agreement. In addition, IPA has entered into the Personnel Service Contract, effective as of June 2, 1982, with Intermountain Power Service Corporation, pursuant to
which certain of the obligations and covenants of IPA under the IPP Power Sales Contracts and the IPA Bond Resolution will be performed and complied with, on behalf of IPA, by said Corporation under said Contract.

Financing Plans

SCPPA will advise IPA in writing on the first business day of each Month of SCPPA’s periodic financing plans and the amount of funds then on deposit in the SCPPA Transmission Project Construction Fund to provide for payments-in-aid of construction to be applied to Southern Transmission Cost of Acquisition and Construction.

On or after the SCPPA First Bonding Date, IPA will not issue any bonds, notes or other evidences of indebtedness to finance, and will not use the proceeds of any bonds, notes or other evidences of indebtedness to pay, Southern Transmission Cost of Acquisition and Construction, except (a) as provided in the STS Agreement, or (b) as otherwise required to avoid any breach or default by IPA under the IPP Power Sales Contracts or the IPA Bond Resolution. Notwithstanding any issuance or use of proceeds by IPA pursuant to clause (b) above, the rights and obligations of SCPPA to undertake financings and make payments-in-aid of construction pursuant to the STS Agreement shall continue (including such rights and obligations as they pertain to that portion of the Southern Transmission Cost of Acquisition and Construction for which such issuance or use of proceeds by IPA was undertaken or made); and IPA shall bill SCPPA, and SCPPA shall make payments-in-aid of construction, with respect to any such portion of the Southern Transmission Cost of Acquisition and Construction in a manner similar to that provided in the STS Agreement with payment for such billing to be made by SCPPA within fifteen days after receipt or such longer period until SCPPA shall have funds available for such payment.

In the event SCPPA shall fail to consummate any financing contemplated by the STS Agreement within the period permitted therein, IPA may, upon prior written notice by IPA to SCPPA, issue its bonds, notes or other evidences of indebtedness to finance, and may use the proceeds of bonds, notes or other evidences of indebtedness to pay, Southern Transmission Cost of Acquisition and Construction.

Upon the giving by IPA of notice in accordance with the STS Agreement, the rights and obligations of SCPPA to undertake financings and make payments-in-aid of construction pursuant to the STS Agreement shall terminate; provided, however, that the then remaining funds in the SCPPA Transmission Project Construction Fund available for such purpose shall continue to be paid to IPA in accordance with the provisions of the STS Agreement.

Budgets; Billings; Payments-in-Aid of Construction

IPA will provide, or cause to be provided, to SCPPA: (i) at the time each revised budget required by the Construction Management and Operating Agreement is approved, a copy of such revised budget as so approved (together with a new computation of STS Direct Costs and STS Allocated Costs based on such revised budget and the then current cost allocation under the STS Agreement); (ii) at the time any revision to any such budget is approved as aforesaid, a copy of such revision (including such a computation); and (iii) with respect to the STS Upgrade Project, (a) at the time each revised operating budget that includes provisions for the STS Upgrade Project (the “STS Upgrade Project Budget”) that has been submitted and approved as required by the Construction Management and Operating Agreement and the IPP Power Sales Contracts is approved, a copy of such revised budget as so approved (together with a computation of STS Direct Costs and STS Allocated Costs based on such STS Upgrade Project Budget and the applicable then current cost allocation under the STS Agreement) and (b) at the time any revision to any STS Upgrade Project Budget is approved.
SCPPA shall be entitled to rely upon each revised budget, requisition or billing provided to it. Any such reliance by SCPPA shall not be deemed a waiver by SCPPA of any rights it may have as a result of a subsequent audit of the costs included therein.

IPA and SCPPA recognize and agree that all payments-in-aid of construction by SCPPA shall be paid from, and only from, funds on deposit and available in the SCPPA Transmission Project Construction Fund and only upon compliance with the requirements of the SCPPA Indenture of Trust regarding the withdrawal and expenditure of funds. Payments-in-aid of construction by SCPPA for the STS Upgrade Project shall be made from funds deposited in the SCPPA Transmission Project Construction Fund from the proceeds of bonds, notes or other evidences of indebtedness issued by SCPPA or from other funds available to it.

All such payments shall be deposited in the appropriate account or accounts under the IPA Bond Resolution. Each such deposit shall be and become part of such account or accounts and IPA will, subject to the lien and pledge of and covenants under the IPA Bond Resolution with respect to such account or accounts, use such deposits only for payment of the Southern Transmission Cost of Acquisition and Construction. Pending application of any such deposit to Southern Transmission Cost of Acquisition and Construction, IPA shall invest all or any portion thereof in accordance with the IPA Bond Resolution.

Neither such payments-in-aid of construction by SCPPA nor the STS Agreement shall change or otherwise affect IPA’s ownership of the Transmission Project or any of the rights and obligations of IPA or the Transmission Project Participants under the IPP Power Sales Contracts, except to the extent that the obligation of IPA to issue its bonds for the payment of the Southern Transmission Cost of Acquisition and Construction is impacted thereby.

IPA, in the STS Agreement, recognizes that, under the IPP Power Sales Contracts, to the extent payments-in-aid of construction by SCPPA are received and applied to the payment of the Southern Transmission Cost of Acquisition and Construction, IPA will not be obligated to issue bonds for the payment of such Cost and consequently, to that extent, Monthly Power Costs allocated to the Transmission Project pursuant to the IPP Power Sales Contracts will be reduced, reflecting the application of such payments to Southern Transmission Cost of Acquisition and Construction in lieu of the issuance of bonds of IPA therefor and the allocation of debt service on such bonds to the Transmission Project.

**Assignment of the Participants’ Rights Under the IPP Power Sales Contracts**

Pursuant to the STS Agreement, IPA consents to the assignment to SCPPA by each Transmission Project Participant of rights under its IPP Power Sales Contract, including its right to the capacity in the Transmission Project, in accordance with the Agreements for the Acquisition of Capacity. SCPPA agrees that it will not sell, assign or otherwise dispose of the rights to capacity in the Transmission Project acquired by it pursuant to the Agreements for the Acquisition of Capacity unless such sale, assignment or disposition (a) is as provided in the Transmission Service Contracts, or (b) is preceded by a resolution of IPA determining (which determination shall not be unreasonably withheld) that such sale, assignment or other disposition will not adversely affect the eligibility for exemption from federal income taxes of the interest paid, or to be paid, on the bonds of IPA with respect to IPP.

**IPP Power Sales Contracts Obligations**

For each month after the SCPPA First Bonding Date, SCPPA will make the payments to IPA required to be made by the Transmission Project Participants pursuant to the IPP Power Sales Contracts for the Monthly Power Costs allocable to the Transmission Project; provided, that, SCPPA shall make such payments only to the extent that funds are available therefor in the Operating Fund established under
the Senior Indenture. Each payment made by SCPPA pursuant to the STS Agreement shall be accompanied by a schedule setting forth the portion thereof being made on behalf of each Transmission Project Participant. For each month after the SCPPA First Bonding Date, for the purpose of determining the payments to be made by SCPPA on behalf of the Transmission Project Participants, IPA in the STS Agreement agrees to provide to SCPPA (concurrent with providing said Billing Statements to the Transmission Project Participants) a copy of the Billing Statement, if any, sent to each Transmission Project Participant pursuant to the IPP Power Sales Contracts.

IPA agrees in the STS Agreement that all payments of Monthly Power Costs made by SCPPA pursuant to the STS Agreement and received by IPA shall be accepted and applied in discharge of the respective Transmission Project Participants’ obligations to pay such Monthly Power Costs under the IPP Power Sales Contracts and the Transmission Project Participants’ obligations to pay such Monthly Power Costs shall be discharged to the extent of the receipt of such payments by IPA. Such payments shall not otherwise affect the rights and obligations of IPA or the Transmission Project Participants under the IPP Power Sales Contracts.
WHEREAS the Board of Directors of the Southern California Public Power Authority, a political subdivision of the State of California ("SCPPA"), has authorized the issuance of SCPPA’s Transmission Project Revenue Bonds, 2015 Subordinate Refunding Series C (the “2015 Series C Subordinate Bonds”) and has authorized the execution by SCPPA of an Indenture of Trust relating to the 2015 Series C Subordinate Bonds, dated as of March 1, 2015, from SCPPA to U.S. Bank National Association, as trustee (the “2015 Series C Subordinated Indenture”); and

WHEREAS, the Board of Directors of SCPPA hereby finds and determines that it is necessary, in connection with the authorization and sale of the 2015 Series C Subordinate Bonds, that SCPPA adopt this resolution in order to assist the Participating Underwriter (such term, and all other capitalized terms used herein without definition, having the respective meanings assigned thereto in Section 1 hereof) in complying with the Rule;

BE IT RESOLVED by the Board of Directors of SCPPA as follows:

1. Definitions. In addition to the definitions set forth in the 2015 Series C Subordinated Indenture, which apply to any capitalized term used in this Disclosure Resolution unless otherwise defined in this Disclosure Resolution, the following capitalized terms shall have the following meanings:

“Annual Report” shall mean any Annual Report provided by SCPPA pursuant to, and as described in, Sections 3 and 4 of this Disclosure Resolution.

“Audited Financial Statements” shall mean:

(a) with respect to SCPPA, SCPPA’s audited financial statements for its most recent fiscal year, prepared in accordance with generally accepted accounting principles as promulgated to apply to governmental entities from time to time (or such other accounting principles as may be applicable to SCPPA in the future pursuant to applicable law);

(b) with respect to LADWP (as defined in Section 2(b) hereof), the audited financial statements of LADWP’s Power System for its most recent fiscal year, prepared in accordance with generally accepted accounting principles as promulgated to apply to governmental entities and public utilities, as appropriate, from time to time (or such other accounting principles as may be applicable to LADWP in the future pursuant to applicable law);

(c) with respect to Riverside (as defined in Section 2(b) hereof), the audited financial statements of Riverside’s Electric System for its most recent fiscal year, prepared in accordance with generally accepted accounting principles as promulgated to apply to governmental entities
from time to time (or such other accounting principles as may be applicable to Riverside in the future pursuant to applicable law); and

(d) with respect to Anaheim (as defined in Section 2(b) hereof), the audited financial statements of Anaheim’s Electric Utility Fund for its most recent fiscal year, prepared in accordance with generally accepted accounting principles as promulgated to apply to governmental entities from time to time (or such other accounting principles as may be applicable to Anaheim in the future pursuant to applicable law).

“Beneficial Owner” shall mean any person holding a beneficial ownership interest in 2015 Series C Subordinate Bonds through nominees or depositaries (including any person holding such interest through the book-entry-only system of The Depository Trust Company), together with any other person who is intended to be a beneficiary of this Disclosure Resolution under the Rule.

“Disclosure Resolution” shall mean this resolution, as the same may be amended or supplemented from time to time in accordance with the provisions hereof.

“Dissemination Agent” shall mean any person or entity appointed by SCPPA and which has entered into a written agreement with SCPPA pursuant to which such person or entity agrees to perform the duties and obligations of Dissemination Agent under this Disclosure Resolution.

“Final Official Statement” shall mean the Official Statement of SCPPA relating to the 2015 Series C Subordinate Bonds, as amended, supplemented or updated.

“Listed Events” shall mean any of the events listed in Section 5(a) of this Disclosure Resolution.

“MSRB” shall mean the Municipal Securities Rulemaking Board established pursuant to Section 15B(b)(1) of the Securities Exchange Act of 1934 or any other entity designated or authorized by the SEC to receive reports pursuant to the Rule. Until otherwise designated by the MSRB or the SEC, filings with the MSRB are to be made through the Electronic Municipal Market Access (EMMA) website of the MSRB, currently located at [http://emma.msrb.org](http://emma.msrb.org).

“Participating Underwriter” shall mean any of the original underwriters of the 2015 Series C Subordinate Bonds (or the underwriter, if there is only one original underwriter) required to comply with the Rule in connection with the offering of the 2015 Series C Subordinate Bonds.

“Rule” shall mean Rule 15c2-12 adopted by the SEC under the Securities Exchange Act of 1934, as amended from time to time, together with all interpretive guidances or other official interpretations or explanations thereof that are promulgated by the SEC.

“SEC” shall mean the United States Securities and Exchange Commission.

2. **Purpose of this Disclosure Resolution; Obligated Persons; Disclosure Resolution to Constitute a Contract.**

(a) This Disclosure Resolution is adopted by SCPPA for the benefit of the Owners and Beneficial Owners of the 2015 Series C Subordinate Bonds and in order to assist the Participating Underwriter in complying with the Rule.

(b) SCPPA, the Department of Water and Power of The City of Los Angeles ("LADWP"), the City of Riverside, California ("Riverside") and the City of Anaheim, California
(“Anaheim”) each are hereby determined by SCPPA to be an “obligated person” within the meaning of the Rule (and are the only “obligated persons” within the meaning of the Rule for whom financial information or operating data are presented in the Final Official Statement). Each such person shall only be an “obligated person” if and for so long as such person is an “obligated person” within the meaning of the Rule.

(c) In consideration of the purchase and acceptance of any and all of the 2015 Series C Subordinate Bonds by those who shall hold the same or shall own beneficial ownership interests therein from time to time, this Disclosure Resolution shall be deemed to be and shall constitute a contract between SCPPA and the Owners and Beneficial Owners from time to time of the 2015 Series C Subordinate Bonds, and the covenants and agreements herein set forth to be performed on behalf of SCPPA shall be for the benefit of the Owners and Beneficial Owners of any and all of the 2015 Series C Subordinate Bonds.

3. Provision of Annual Reports.

(a) SCPPA hereby covenants and agrees that it shall, or shall cause the Dissemination Agent to, not later than six months after the end of each fiscal year of SCPPA (presently, by each December 31, each such date being referred to herein as a “Final Submission Date”), commencing with the report for fiscal year 2014-15, provide to the MSRB an Annual Report which is consistent with the requirements of Section 4 of this Disclosure Resolution. The Annual Report may be submitted as a single document or as separate documents comprising a package, and may include by reference other information as provided in Section 4 of this Disclosure Resolution; provided that any Audited Financial Statements may be submitted separately from the balance of the Annual Report and later than the Final Submission Date if they are not available by that date. If the fiscal year for SCPPA, LADWP, Riverside or Anaheim changes, SCPPA shall give notice of such change in the same manner as for a Listed Event under Section 5(c).

(b) Not later than ten (10) business days prior to each Final Submission Date (each such date being referred to herein as a “Preliminary Submission Date”), SCPPA shall provide the Annual Report to the Dissemination Agent, if any. If by a Preliminary Submission Date, the Dissemination Agent, if any, has not received a copy of the Annual Report, the Dissemination Agent shall contact SCPPA to determine if SCPPA is in compliance with subsection (a).

(c) If SCPPA or the Dissemination Agent (if any), as the case may be, has not provided any Annual Report to the MSRB by a Final Submission Date, SCPPA or the Dissemination Agent, as applicable, shall provide a notice to the MSRB in substantially the form attached hereto as Exhibit A.

(d) SCPPA (or, in the event that SCPPA shall appoint a Dissemination Agent hereunder, the Dissemination Agent) shall provide the Annual Report to the MSRB on or before the Final Submission Date. In addition, if SCPPA shall have appointed a Dissemination Agent hereunder, the Dissemination Agent shall file a report with SCPPA certifying that the Annual Report has been provided to the MSRB pursuant to this Disclosure Resolution and stating the date it was provided.

(e) Any Annual Report must be submitted in electronic format, accompanied by such identifying information as is prescribed by the MSRB.
4. **Content of Annual Reports.** SCPPA’s Annual Report shall contain or include by reference the following:

(a) If available at the time of filing of the Annual Report as provided herein, the Audited Financial Statements of SCPPA, LADWP, Riverside and Anaheim for the most recently ended fiscal year. If any Audited Financial Statements are not available by the Final Submission Date, the Annual Report shall contain unaudited financial statements for SCPPA, LADWP, Riverside or Anaheim, as applicable, in a format similar to the audited financial statements most recently prepared for such obligated person, and such Audited Financial Statements shall be filed in the same manner as the Annual Report when and if they become available.

(b) Updated versions of the type of information contained in the Final Official Statement relating to the following:

   1. operation and maintenance and operating statistics of the Project as set forth under the section entitled “THE SOUTHERN TRANSMISSION PROJECT” and under the subsection entitled “INTERMOUNTAIN POWER PROJECT - Operating Statistics” in Appendix B.

   2. the debt service requirements contained in Appendix F to the Final Official Statement.

(c) Updated versions of the type of information for LADWP contained in Appendix A to the Final Official Statement relating to the following:

   1. the description of operations and the summary of operating results of LADWP’s Power System; and

   2. the summary of financial results of LADWP’s Power System.

(d) Updated versions of the type of information for Riverside contained in Appendix A to the Final Official Statement relating to the following:

   1. the description of operations and the summary of operating results of Riverside’s Electric System; and

   2. the summary of financial results of Riverside’s Electric System.

(e) Updated versions of the type of information for Anaheim contained in Appendix A to the Final Official Statement relating to the following:

   1. the description of operations and the summary of operating results of the Anaheim Public Utilities electric system (the “Anaheim Electric System”); and

   2. the summary of financial results of Anaheim’s Electric System.

(f) If known to SCPPA, the name, address and telephone number of a place where current information regarding any bond insurer with respect to the 2015 Series C Subordinate Bonds (the “Bond Insurer”) may be obtained.
Any or all of the items listed above may be included by specific reference to other documents, including Annual Reports of SCPPA, LADWP, Riverside or Anaheim or official statements relating to debt or other securities issues of SCPPA, LADWP, Riverside, Anaheim or other entities, which have been submitted to the MSRB. If the document included by reference is a final official statement (as defined in the Rule), it must be available from the MSRB. SCPPA shall clearly identify each such other document so included by reference.

5. Reporting of Significant Events.

(a) Pursuant to the provisions of this Section 5, SCPPA hereby covenants and agrees that it shall give, or cause to be given, notice of the occurrence of any of the following events with respect to the 2015 Series C Subordinate Bonds:

1. principal or interest payment delinquencies;

2. non-payment related defaults, if material;

3. modifications to the rights of the Bondholders, if material;

4. optional, contingent or unscheduled calls, if any of the preceding are material, and tender offers;

5. defeasances;

6. rating changes;

7. adverse tax opinions or the issuance by the Internal Revenue Service of proposed or final determinations of taxability, Notices of Proposed Issue (IRS Form 5701-TEB) or other material notices or determinations with respect to the tax status of a 2015 Series C Subordinate Bond or other material events affecting the tax status of a 2015 Series C Subordinate Bond;

8. unscheduled draws on debt service reserves reflecting financial difficulties;

9. unscheduled draws on credit enhancements reflecting financial difficulties;

10. substitution of credit or liquidity providers or their failure to perform;

11. release, substitution or sale of property securing repayment of the 2015 Series C Subordinate Bonds, if material;

12. bankruptcy, insolvency, receivership or similar proceedings described below of SCPPA, LADWP, Riverside or Anaheim;

13. appointment of a successor or additional trustee or the change of name of a trustee, if material; or

14. the consummation of a merger, consolidation, or acquisition involving SCPPA, LADWP, Riverside or Anaheim or the sale of all or substantially all of the assets of the Southern Transmission Project other than in the ordinary course of business, the entry into a definitive agreement to undertake such an action or the
termination of a definitive agreement relating to any such actions, other than pursuant to its terms, if material.

(b) An event described in item 12 above of Section 5(a) is considered to occur when any of the following occur: the appointment of a receiver, fiscal agent, or similar officer for SCPPA, LADWP, Riverside or Anaheim in a proceeding under the United States Bankruptcy Code or in any other proceeding under state or federal law in which a court or governmental authority has assumed jurisdiction over substantially all of the assets or business of said party, or if such jurisdiction has been assumed by leaving the existing governing body and officials or officers in possession but subject to the supervision and orders of a court or governmental authority, or the entry of an order confirming a plan of reorganization, arrangement, or liquidation by a court or governmental authority having supervision or jurisdiction over substantially all of the assets or business of said party.

(c) SCPPA shall provide notice of an occurrence of a Listed Event to the MSRB in a timely manner but not more than ten (10) business days after the occurrence of the event. Any notice of Listed Event(s) must be submitted to the MSRB in electronic format, accompanied by such identifying information as is prescribed by the MSRB.

6. Management’s Discussion of Items Disclosed in Annual Reports or as Significant Events. If an item required to be disclosed in SCPPA’s Annual Report under Section 4, or as a Listed Event under Section 5, would be misleading without discussion, SCPPA additionally covenants and agrees that it shall provide a statement clarifying the disclosure in order that the statement made will not be misleading in the light of the circumstances under which it is made.

7. Termination of Reporting Obligations. SCPPA’s obligations under this Disclosure Resolution shall terminate upon the legal defeasance, prior redemption or payment in full of all of the 2015 Series C Subordinate Bonds. In addition, in the event that the Rule shall be amended, modified or repealed such that compliance by SCPPA with its obligations under this Disclosure Resolution no longer shall be required in any or all respects, then SCPPA’s obligations under this Disclosure Resolution shall terminate to a like extent. If either such termination occurs prior to the final maturity of the 2015 Series C Subordinate Bonds, SCPPA shall give notice of such termination in the same manner as for a Listed Event under Section 5(c).

8. Dissemination Agent. SCPPA may, from time to time, appoint or engage a Dissemination Agent to assist it in carrying out its obligations under this Disclosure Resolution, and may discharge any such Dissemination Agent, with or without appointing a successor Dissemination Agent.

9. Amendment; Waiver.

(a) Notwithstanding any other provision of this Disclosure Resolution, SCPPA may, by resolution hereafter adopted, amend this Disclosure Resolution, and any provision of this Disclosure Resolution may be waived, provided that, in the opinion of nationally-recognized bond counsel, such amendment or waiver is permitted by the Rule.

(b) The Annual Report containing any modified operating data or financial information as a result of an amendment shall explain, to the extent required by the Rule, in narrative form, the reasons for the amendment and the impact of the change in the type of operating data or financial information being provided. If a change in accounting principles is included in any such modification, such Annual Report shall present, to the extent required by the Rule, a comparison between the financial statements or information prepared on the basis of the modified accounting principles and those prepared on the basis of the former accounting principles.
10. **Additional Information.** Nothing in this Disclosure Resolution shall be deemed to prevent SCPPA from disseminating, or require SCPPA to disseminate, any other information using the means of dissemination set forth in this Disclosure Resolution or any other means of communication, or including any other information in any Annual Report or notice of occurrence of a Listed Event, in addition to that which is required by this Disclosure Resolution. If SCPPA chooses to include any information in any Annual Report or notice of occurrence of a Listed Event in addition to that which is specifically required by this Disclosure Resolution, SCPPA shall have no obligation under this Disclosure Resolution to update such information or include it in any future Annual Report, notice of occurrence of a Listed Event or other materials disseminated hereunder.

11. **Default.**

(a) In the event of a failure of SCPPA to comply with any provision of this Disclosure Resolution, any Owner or Beneficial Owner of any Outstanding 2015 Series C Subordinate Bonds may take such actions as may be necessary and appropriate, including seeking mandamus or specific performance by court order, for the equal benefit and protection of all Owners or Beneficial Owners similarly situated, to cause SCPPA to comply with its obligations under this Disclosure Resolution.

(b) Notwithstanding the foregoing, no Owner or Beneficial Owner of the 2015 Series C Subordinate Bonds shall have the right to challenge the content or adequacy of the information provided pursuant to Sections 3, 4 or 5 of this Disclosure Resolution by mandamus, specific performance or other equitable proceedings unless Owners or Beneficial Owners of 2015 Series C Subordinate Bonds representing at least 25% in aggregate principal amount of the Outstanding affected 2015 Series C Subordinate Bonds shall join in such proceedings.

(c) A default under this Disclosure Resolution shall not be deemed an Event of Default under the 2015 Series C Subordinated Indenture, and the sole remedies under this Disclosure Resolution in the event of any failure of SCPPA to comply with this Disclosure Resolution shall be those described in subsection (a) above.

(d) Under no circumstances shall any person or entity be entitled to recover monetary damages hereunder in the event of any failure of SCPPA to comply with this Disclosure Resolution.

12. **Duties, Immunities and Liabilities of Dissemination Agent.** Any Dissemination Agent appointed hereunder shall have only such duties as are specifically set forth in this Disclosure Resolution and shall have such rights, immunities and liabilities as shall be set forth in the written agreement between SCPPA and such Dissemination Agent pursuant to which such Dissemination Agent agrees to perform the duties and obligations of Dissemination Agent under this Disclosure Resolution.

13. **Beneficiaries.** This Disclosure Resolution shall inure solely to the benefit of SCPPA, the Dissemination Agent, if any, and the Owners and Beneficial Owners from time to time of the 2015 Series C Subordinate Bonds, and, subject to Section 2(a) hereof, shall create no rights in any other person or entity.

14. **Governing Law.** This Disclosure Resolution shall be deemed to be a contract made under the Rule and the laws of the State of California, and for all purposes shall be construed and interpreted in accordance with, and its validity governed by, the Rule and the laws of the State of California, without regard to principles of conflicts of law.
15. **Effective Date.** This Disclosure Resolution shall become effective upon the date of authentication and delivery of the 2015 Series C Subordinate Bonds.

THE FOREGOING RESOLUTION is approved and adopted by SCPPA this 19th day of February, 2015.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

_______________________________________
PRESIDENT
Southern California Public Power Authority

ATTEST:

_______________________________________
ASSISTANT SECRETARY
Southern California Public Power Authority
EXHIBIT A

NOTICE TO REPOSITORIES OF FAILURE TO FILE ANNUAL REPORT

Name of Issuer: Southern California Public Power Authority

Name of Bond Issue: $___________ Transmission Project Revenue Bonds, 2015 Subordinate Refunding Series C

Date of Issuance: ____________, 2015

NOTICE IS HEREBY GIVEN that Southern California Public Power Authority (“SCPPA”) has not provided an Annual Report with respect to the above-named Bonds as required by Section 3(a) of Resolution No. 2015-016, adopted by the Board of Directors of SCPPA on February 19, 2015 relating to the above-named Bonds. [SCPPA [has advised the undersigned that SCPPA] anticipates that the Annual Report will be filed by ________________.]  

Dated: ________________  

[SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY]

[________________, as Dissemination Agent on behalf of Southern California Public Power Authority]

[cc: Southern California Public Power Authority]
PROPOSED FORM OF CO-BOND COUNSEL OPINION

On the delivery date of the 2015 Series C Subordinate Bonds, Norton Rose Fulbright US LLP, Los Angeles, California, and Curls Bartling P.C., Oakland, California, Co-Bond Counsel, propose to render their final approving opinion in substantially the following form:

[Delivery Date]

Board of Directors
Southern California Public Power Authority
1160 Nicole Court
Glendora, California 91740

Re: Southern California Public Power Authority
Transmission Project Revenue Bonds, 2015 Subordinate Refunding Series C

Ladies and Gentlemen:

We have examined a record of proceedings relating to the issuance of $116,535,000 aggregate principal amount of Transmission Project Revenue Bonds, 2015 Subordinate Refunding Series C (the “2015 Series C Subordinate Bonds”) by the Southern California Public Power Authority (the “Authority”), a public entity of the State of California, and such other matters of law as we have deemed necessary to enable us to render the opinions expressed herein.

The 2015 Series C Subordinate Bonds are issued under and pursuant to 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 Article 11 of Chapter 3 of Part 1 of Division 2 of Title 5 of the Government Code of California (the “Act”). The 2015 Series C Subordinate Bonds are issued under and pursuant to an Indenture of Trust, dated as of March 1, 2015 (the “2015 Series C Subordinated Indenture”), from the Authority to U.S. Bank National Association, as trustee (the “Trustee”).

The 2015 Series C Subordinate Bonds are dated, and shall bear interest from, their date of delivery. Interest on the 2015 Series C Subordinate Bonds is payable semiannually on January 1 and July 1 of each year, commencing on July 1, 2015. The 2015 Series C Subordinate Bonds mature and are subject to prior redemption as provided in the 2015 Series C Subordinated Indenture.

The 2015 Series C Subordinate Bonds will be issued in denominations of $5,000 or any integral multiple thereof. The 2015 Series C Subordinate Bonds will be issued in fully registered form, are interchangeable and transferable as provided in the 2015 Series C Subordinated Indenture, and are lettered and numbered as provided therein.

The 2015 Series C Subordinate Bonds are issued for the purpose of providing moneys to: (i) refund the Refunded Bonds (as defined in the Twenty-Eighth Supplemental Indenture of Trust relating to the 2015 Series C Subordinate Bonds, dated as of March 1, 2015 (the “Supplemental Indenture”), from the Authority to U.S. Bank National Association, as trustee); and (ii) pay the costs of issuance of the 2015 Series C Subordinate Bonds. The Refunded Bonds were issued pursuant to an Indenture of Trust, dated as of November 1, 2008, from the Authority to U.S. Bank National Association, as trustee, for the primary purpose of financing the cost of construction of certain improvements to the Intermountain Power Project Southern Transmission System, specifically the upgrade of its two converter stations. The 2015
Series C Subordinate Bonds are payable from Pledged Revenues (as defined in the 2015 Series C Subordinated Indenture) and the 2015 Series C Issue Fund and all accounts established therein relating to the 2015 Series C Subordinate Bonds, subject only to the provisions of the 2015 Series C Subordinated Indenture permitting the application thereof for the purposes and on the terms and conditions set forth therein.

The Authority has entered into six separate Transmission Service Contracts (the “Transmission Service Contracts”) with the following purchasers (the “Project Participants”) of transmission service utilizing Authority Capacity (as defined in the 2015 Series C Subordinated Indenture and the Indenture of Trust, dated as of May 1, 1983, from the Authority to U.S. Bank National Association, as successor trustee (as amended and supplemented, the “Senior Indenture”)): the Department of Water and Power of The City of Los Angeles and the Cities of Anaheim, Riverside, Pasadena, Burbank and Glendale.

Capitalized terms not defined herein shall have the respective meanings set forth in the Senior Indenture or the 2015 Series C Subordinated Indenture, as applicable.

From such examination, we are of the opinion that:

1. The Authority has been duly created and is validly existing under the provisions of the Act and has the right and authority under the Act to acquire and utilize Authority Capacity.

2. The Authority has the right and authority to enter into and carry out its obligations under the Transmission Service Contracts and has duly authorized, executed and delivered the Transmission Service Contracts which constitute valid and binding agreements of the Authority, enforceable in accordance with their terms.

3. The Authority has the right and authority under the Act to enter into the 2015 Series C Subordinated Indenture, the 2015 Series C Subordinated Indenture has been duly and lawfully authorized, executed and delivered by the Authority, and assuming due authorization, execution and delivery by, and enforceability against, the other party thereto, is in full force and effect in accordance with its terms and is valid and binding upon the Authority and enforceable in accordance with its terms, and no other authorization for the 2015 Series C Subordinated Indenture is required. The 2015 Series C Subordinated Indenture creates the valid pledge that it purports to create of (i) the Pledged Revenues and (ii) the 2015 Series C Issue Fund and all accounts established therein relating to the 2015 Series C Subordinate Bonds, subject only to the provisions of the 2015 Series C Subordinated Indenture permitting the application thereof for the purposes and on the terms and conditions set forth therein.

4. The Authority is duly authorized and entitled to issue the 2015 Series C Subordinate Bonds, and the 2015 Series C Subordinate Bonds have been duly and validly authorized and issued by the Authority in accordance with the Constitution and statutes of the State of California, including the Act, and the 2015 Series C Subordinated Indenture. The 2015 Series C Subordinate Bonds constitute valid and binding obligations of the Authority as provided in the 2015 Series C Subordinated Indenture, are enforceable in accordance with their terms and the terms of the 2015 Series C Subordinated Indenture, and are entitled to the benefits of the Act and the 2015 Series C Subordinated Indenture. The 2015 Series C Subordinate Bonds are not an obligation of the State of California, any public agency thereof (other than the Authority), any member of the Authority or the Project Participants and neither the faith and credit nor the taxing power of any of the foregoing (including the Authority) is pledged for the payment of the 2015 Series C Subordinate Bonds. The Authority has no taxing power.
5. Under the Constitution and laws of the State of California, each Transmission Service Contract constitutes a valid and binding agreement of the Project Participant party thereto enforceable in accordance with its terms. In rendering the foregoing opinion, we have made no investigation of, and do not express any opinion with respect to, the following as they may relate to the valid, binding and enforceable nature of such Transmission Service Contracts: (i) the legal existence or formation of any Project Participant or the incumbency of any official or officer thereof; (ii) any local or special acts or any ordinance, resolution or other proceedings of any Project Participant, including, without limitation, any proceedings relating to the negotiation or authorization of any Transmission Service Contract or the execution, delivery or performance thereof (except that we have examined the ordinances pursuant to which the respective Transmission Service Contracts were authorized by the respective Project Participants); (iii) any bond resolution, indenture, contract, debt instrument, agreement or other instrument (other than such Transmission Service Contracts) or any governmental order, regulation or rule of or applicable to any Project Participant; (iv) any judicial order, judgment or decree in a proceeding to which any Project Participant is a party; or (v) any approval, consent, filing, registration or authorization by or with any regulatory authority or other governmental or public agency, authority or person that may be or has been required for the authorization, execution, delivery or performance by any Project Participant of its Transmission Service Contract. The Authority has heretofore received, independent from this opinion, opinions with respect to, among other things, the validity and enforceability of the Transmission Service Contracts rendered by legal counsel to the respective Project Participants.

6. Under existing law, interest on the 2015 Series C Subordinate Bonds is exempt from personal income taxes of the State of California and, assuming compliance with the covenants described below, interest on the 2015 Series C Subordinate Bonds is excluded pursuant to section 103(a) of the Internal Revenue Code of 1986 (the “Code”) from the gross income of the owners thereof for federal income tax purposes. The 2015 Series C Subordinate Bonds are not “specified private activity bonds” within the meaning of section 57(a)(5) of the Code and, therefore, the interest on the 2015 Series C Subordinate Bonds will not be treated as an item of tax preference for purposes of computing the alternative minimum tax imposed by section 55 of the Code. However, the receipt or accrual of interest on 2015 Series C Subordinate Bonds owned by a corporation may affect the computation of its alternative minimum taxable income, upon which the alternative minimum tax is imposed.

The Code imposes certain requirements that must be met subsequent to the issuance and delivery of the 2015 Series C Subordinate Bonds for interest thereon to be and remain excluded from the gross income of the owners thereof for federal income tax purposes. Non-compliance with such requirements could cause the interest on the 2015 Series C Subordinate Bonds to fail to be excluded from the gross income of the owners thereof retroactive to the date of issue of the 2015 Series C Subordinate Bonds. The Authority has covenanted in the 2015 Series C Subordinated Indenture, and each of the Project Participants has covenanted in its Transmission Service Contract, not to take any action or omit to take any action which, if taken or omitted, respectively, would adversely affect the exclusion of the interest on the 2015 Series C Subordinate Bonds from the gross income of the owners thereof for federal income tax purposes. Except as stated in the preceding paragraph, we express no opinion as to any federal, state or local tax consequences of the ownership or disposition of the 2015 Series C Subordinate Bonds. Furthermore, we express no opinion as to any federal, state or local tax law consequences with respect to the 2015 Series C Subordinate Bonds, or the interest thereon, if any action is taken with respect to the 2015 Series C Subordinate Bonds or the proceeds thereof upon the advice or approval of other counsel.
Our opinions are based on existing law, which is subject to change. Such opinions are further based on our knowledge of facts as of the date hereof and are rendered in reliance upon certificates of officers of the Authority and the Project Participants relating to the expected use of the facilities financed or refinanced with the proceeds of the 2015 Series C Subordinate Bonds and other matters relevant to the status of the 2015 Series C Subordinate Bonds under section 103 of the Code. We assume no duty to update or supplement our opinions to reflect any facts or circumstances that may hereafter come to our attention or to reflect any changes in any law that may hereafter occur or become effective. Moreover, our opinions are not a guarantee of result and are not binding on the Internal Revenue Service; rather, such opinions represent our legal judgment based upon our review of existing law that we deem relevant to such opinions and in reliance upon the representations and covenants referenced above.

No opinion is expressed herein on the accuracy, completeness or sufficiency of the Official Statement or other offering material relating to the 2015 Series C Subordinate Bonds.

The opinions expressed in paragraphs 2, 3, 4 and 5 hereof are qualified to the extent that the enforceability of the Senior Indenture, the 2015 Series C Subordinated Indenture, the 2015 Series C Subordinate Bonds and the Transmission Service Contracts may be limited by any applicable bankruptcy, insolvency, debt adjustment, moratorium, reorganization or other similar laws affecting creditors’ rights generally or as to the availability of any particular remedy. The enforceability of the Senior Indenture, the 2015 Series C Subordinated Indenture, the 2015 Series C Subordinate Bonds and the Transmission Service Contracts is subject to the effect of general principles of equity, including, without limitation, concepts of materiality, reasonableness, good faith and fair dealing, to the possible unavailability of specific performance or injunctive relief, regardless of whether considered in a proceeding in equity or at law, and to the limitations on legal remedies against governmental entities in California (including, but not limited to, rights of indemnification).

Very truly yours,
### APPENDIX F

**ESTIMATED DEBT SERVICE REQUIREMENTS**  
(Accrual Basis)

<table>
<thead>
<tr>
<th>Fiscal Year Ending June 30</th>
<th>Subordinate Bonds (other than 2015 Series C Subordinate Bonds)&lt;sup&gt;(1)(2)&lt;/sup&gt;</th>
<th>2015 Series C Subordinate Bonds</th>
<th>Combined Debt Service&lt;sup&gt;(3)&lt;/sup&gt;</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Principal</td>
<td>Interest</td>
<td>Principal</td>
</tr>
<tr>
<td>2015</td>
<td>$53,085,000</td>
<td>$24,395,417</td>
<td>$ -</td>
</tr>
<tr>
<td>2016</td>
<td>53,650,000</td>
<td>22,382,623</td>
<td>-</td>
</tr>
<tr>
<td>2017</td>
<td>54,315,000</td>
<td>20,499,064</td>
<td>-</td>
</tr>
<tr>
<td>2018</td>
<td>56,100,000</td>
<td>17,854,081</td>
<td>-</td>
</tr>
<tr>
<td>2019</td>
<td>49,005,000</td>
<td>15,098,196</td>
<td>-</td>
</tr>
<tr>
<td>2020</td>
<td>64,465,000</td>
<td>12,767,208</td>
<td>-</td>
</tr>
<tr>
<td>2021</td>
<td>82,410,000</td>
<td>10,273,167</td>
<td>-</td>
</tr>
<tr>
<td>2022</td>
<td>64,505,000</td>
<td>6,454,625</td>
<td>-</td>
</tr>
<tr>
<td>2023</td>
<td>66,655,000</td>
<td>3,330,875</td>
<td>-</td>
</tr>
<tr>
<td>2024</td>
<td>-</td>
<td>-</td>
<td>27,055,000</td>
</tr>
<tr>
<td>2025</td>
<td>-</td>
<td>-</td>
<td>28,390,000</td>
</tr>
<tr>
<td>2026</td>
<td>-</td>
<td>-</td>
<td>29,805,000</td>
</tr>
<tr>
<td>2027</td>
<td>-</td>
<td>-</td>
<td>31,285,000</td>
</tr>
<tr>
<td>Total&lt;sup&gt;(3)&lt;/sup&gt;</td>
<td>$544,190,000</td>
<td>$133,055,255</td>
<td>$116,535,000</td>
</tr>
</tbody>
</table>

<sup>(1)</sup> Excludes the 2008 Series B Subordinate Bonds to be refunded.

<sup>(2)</sup> Assumes that the 2015 Series A and B Subordinate Bonds are issued and delivered.

<sup>(3)</sup> Total may not add due to rounding.
SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY • TRANSMISSION PROJECT REVENUE BONDS, 2015 SUBORDINATE REFUNDING SERIES C (SOUTHERN TRANSMISSION PROJECT)